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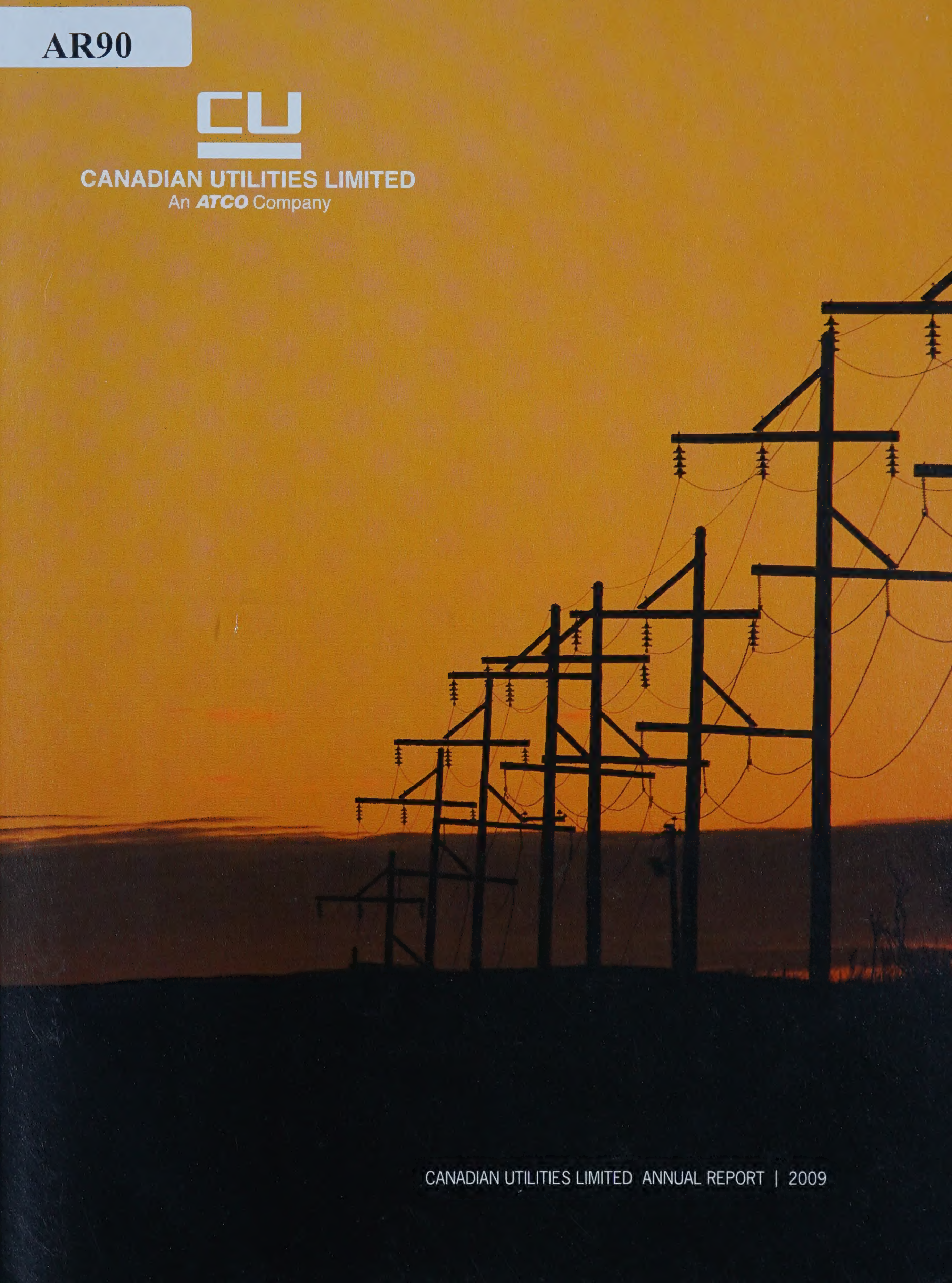
CANADIAN UTILITIES LIMITED
An ATCO Company



CANADIAN UTILITIES LIMITED ANNUAL REPORT | 2009

2009 Canadian Utilities Limited Annual Report

Canadian Utilities Limited is a diversified, Canadian-based, international group of companies focused on profitable sustainable growth and achievement with approximately $9.1 billion in assets and more than 5,700 people actively engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation and natural gas gathering, processing and storage and liquids extraction) and Technologies (business systems solutions).

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COVER PHOTO
Transmission lines on a country road at sunset just outside of Drumheller, Alberta.

Canadian Utilities Limited Financial Highlights

CONSOLIDATED ANNUAL RESULTS

	Year End December 31	
(Millions of Canadian dollars except per share data)	**2009**	2008
FINANCIAL		
Revenues	**2,584.0**	2,778.9
Earnings attributable to Class A & Class B shares	**466.6**	414.5
Adjusted earnings	**427.6**	403.2
Total assets	**9,083.6**	7,860.0
Class A & B share owners' equity	**3,046.1**	2,748.5
Funds generated by operations	**793.4**	796.5
Capital expenditures	**946.1**	1,010.9
CLASS A NON-VOTING & CLASS B VOTING SHARE DATA		
Earnings per share	**3.71**	3.30
Diluted earnings per share	**3.71**	3.29
Adjusted earnings per share	**3.40**	3.21
Dividends paid per share	**1.41**	1.33
Equity per share	**24.20**	21.90
Shares outstanding (thousands)	**125,860**	125,510
Weighted average shares outstanding (thousands)	**125,637**	125,408

The above data (other than adjusted earnings, funds generated by operations and adjusted earnings per share) has been extracted from financial statements which have been prepared in accordance with Generally Accepted Accounting Principles and the reporting currency is the Canadian dollar.

For further information please see Canadian Utilities Limited Consolidated Financial Statements and Management's Discussion and Analysis - www.sedar.com.

Forward-looking Information:

Certain statements contained in this Annual Report constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expectations reflected in forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

President's Letter to Share Owners

Nancy C. Southern
Deputy Chair, President & Chief Executive Officer

Dear Share Owners,

2009 is a year that will not easily be forgotten; the global financial crisis and a looming severe international recession shook the foundations of corporate and consumer confidence throughout the developed world.

Extraordinary fiscal and monetary policies were applied to stabilize threatened economies with varying degrees of success.

As I write to you today, there are still tremors and aftershocks appearing around the world that make the prospects of a strong worldwide recovery fragile indeed.

Against this backdrop, in January 2009, Canadian Utilities (CU) implemented two key performance enhancement objectives:

- Operational Savings
- Cash Improvement

With a self-imposed urgency on these matters, a capital budget of close to $1 billion and commodity prices, particularly power pool prices, negatively impacted by over supply and curtailed demand, our executive teams in our principal operating subsidiaries and corporate office aggressively engaged on a line-by-line basis to find efficiency improvements in our general and administrative costs as well as applying a stern rigour to our capital projects.

The net result was improved profitability by year end of almost $467 million, a record year for CU, and close to $800 million of cash available on a consolidated basis.

These performance enhancement measures have also provided a more competitive base for CU as we enter 2010.

Your Company also experienced good success and progress on a number of strategies.

On July 1, 2009, ATCO Structures & Logistics Ltd. was formed. This was the culmination of many months of work performed by CU and ATCO Ltd. special Board Committees to bring the products and services of ATCO Structures, ATCO Frontec and ATCO Noise Management together under one company. ATCO Ltd. now owns 75.5% of the new company and CU owns 24.5%.

The formation of ATCO Structures & Logistics successfully blends the products and services required by our customers into one worldwide company. The new ATCO Structures & Logistics provides manufactured camps, camp services and logistical support to resource industry customers; facility management and operations and logistical support to defence clients, such as North Atlantic Treaty Organization (NATO), North American Aerospace Defense Command (NORAD) and The Canadian Department of Defence; rapid deployment solutions for emergency situations, such as experienced in Pakistan, Haiti and Chile, as well as the traditional workforce housing and space rental products, along with noise attenuation solutions on industrial sites.

The formation of ATCO Structures & Logistics was the first step in realigning the group's business segments. The two key business segments are: Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric); and, Energy (ATCO Power, ATCO Midstream and ATCO Energy Solutions). This strategy is designed to optimize the management skills and talents of complementary businesses creating a stronger, somewhat simplified platform for future growth.

ATCO I-Tek is now reported under the 'Corporate & Other' segment and remains an engine to CU's earnings and prospective opportunities.

Progress was also made on components of our 'Green Energy Corridor' strategy that we initiated several years ago. This concept envisions the replacement and reduction of greenhouse gas emissions by providing clean electricity for Alberta from 'run-of-river' hydro generation facilities in Alberta's north and the Northwest Territories.

ATCO Electric was authorized by the Alberta Electric System Operator to prepare a facilities application for the Alberta Utilities Commission to approve the corridor, construction and operations of a 500 kilovolt, direct current, high-voltage transmission line to run down the east side of Alberta. The project is deemed as 'critical infrastructure' by the Province and is estimated to be an investment of more than $1 billion for ATCO Electric. Construction is slated to begin in late 2010.

In 2009, CU invested more than $900 million in capital projects, the majority of which was spent by our Utility Companies on infrastructure within Alberta, while ATCO Power commenced construction on the 86 megawatt, gas-fired Karratha Power Station in Western Australia.

In the past five years, your Company has invested $3.7 billion in new projects while maintaining a strong cash position on our balance sheet, earnings and dividend growth and no dilution to your ownership in the Company.

Dividends ($)

*excludes $0.25 special dividend

Earnings Per Share ($)

Assets ($ Billions)

I want to thank my colleagues in the Office of the Chairman, the Presidents, and their Executive Teams, and the more than 5,700 men and women of CU who, amidst the rippling effects of a deep global recession, preemptively prepared to husband our resources, strengthen our internal processes and still delivered growth in our earnings. They did this with a commitment to the safe, reliable and environmentally conscious delivery of goods and services to our customers.

I would like to add a special thank you to Karen Watson and Michael Shaw; two senior executives who retired in 2009.

Michael Shaw retired as Managing Director, Strategic Planning, after 30 years of service in a variety of roles throughout our Company where he influenced or led many of CU's success stories.

Karen Watson retired as our Senior Vice President & Chief Financial Officer after joining ATCO in 1976. CU's strong credit rating, detailed financial controls, high reporting standards and exemplary disclosure are a small part of the legacy Karen leaves with us.

2009 was a year of good achievements and at the heart of our accomplishments was the sage counsel and guidance provided by our extraordinary Board of Directors and Chairman. Thank you!

In closing, I also want to thank you, the owners of Canadian Utilities, for your letters of support and encouragement.

Warmest regards,

N.C. Southern

N.C. Southern
Deputy Chair, President & Chief Executive Officer

Five-Year Total Return on $100 Investment

CANADIAN UTILITIES LIMITED CLASS A NON-VOTING AND CLASS B VOTING SHARES

Canadian Utilities Limited Share Ownership

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern family holding company.

It is also important for present and prospective share owners to understand that Canadian Utilities share registry has both non-voting and voting common shares.

	Compound Growth Rate	Cumulative Return
Class A Non-Voting	11.2%	$170
Class B Voting	9.9%	$160
S&P/TSX Composite	7.7%	$145

The graph compares the cumulative share owner return over the last five years on the Class A Non-Voting and Class B Voting shares of the Corporation (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index.

Chairman's Letter

Ronald D. Southern
Chairman of the Board

2009 progressed with many unfavourable scenarios unfolding and all things moving at the same moment with broad negative consequences for many governments, corporations, and individuals. The distressing severity varied - but, as your President reports, even though Canadian Utilities' results were in a great balance, we came out on the right side of the scale.

Directors and senior officers started the year off in a timely fashion with an effective strategy conference, which went far beyond number crunching, and focused on those areas in which they believe we can be most successful in the future. This strategic and tactical interchange between directors and executives continued during each two-day quarterly board meeting for the better part of a day.

Our tactics flowing from those discussions, have given a new found determination to re-structure parts of our organization; to deploy our financial and human resources with full force into our sectoral and geographic opportunities; continuing to strengthen our balance sheet; and achieving sustainable profitability in the face of what we all agree will be uncertainty through a long-term business cycle involving many structural economic variants.

Your President's letter features the Group's achievements in this regard.

While all of this continues to be a work-in-progress, your Board of Directors would like, on behalf of our Share Owners, to compliment our executives who lead the company, and all of their people for their record achievements with respect to strengthening our financial reserves, and with respect to the Canadian Utilities dividends per share which have increased for 37 consecutive years.

Equally, to compliment them on the strategic focus of their organizational changes, especially in bringing together two distinct share registries of Canadian Utilities and ATCO – namely ATCO Frontec's logistics business, and ATCO Structures' manufacturing and leasing business, into what is now fully operational as ATCO Structures & Logistics Ltd., proportionately owned by the two registries. As their Chairman, I would like to compliment the separate and distinct special committees of Directors who achieved this beneficial result.

2010 and the future are far from clear. There remains a danger of double-dip recession; a jobless recovery; deflation; inflation; or even stagflation.

Default problems may still be a major issue in commercial property and real estate, and meaningful reform in the global financial system to improve its reliability still seems quite elusive.

Your Board of Directors continues to counsel our officers to maintain the strongest possible financial positions, and to conduct their affairs with steady nerves as we enter the second decade of this century when we believe we will be privy to meaningful opportunities.

Your Directors also wish to thank all the people who build our endeavours for their loyalty, performance, and their supreme virtue of action which bring the ATCO heart and mind attitude of "yes we can" to all we do.

May we also express to our Share Owners our sincere appreciation for the trust and confidence you place in us.

Respectfully submitted,

R. D. Southern
Chairman of the Board

Creating a Green Corridor

Siegfried W. Kiefer
Managing Director, Utilities

As ATCO Group's principal operating subsidiary, Canadian Utilities (CU) has been finding cleaner ways to produce energy for decades. From emissions-free hydro power to heating homes and buildings with geothermal technology, our companies continue to innovate.

Our Group is recognized as a leader in developing environmentally responsible co-generation power plants and our long-term vision includes a plan for sustainable energy with a transmission corridor that links north to south.

ATCO's Green Corridor begins in Canada's north with the development of hydro generation projects. The Mackenzie, Peace, Athabasca and Slave rivers offer opportunity for several thousand megawatts of clean, green energy. We believe these hydro developments could eventually be a replacement for Alberta's coal-fired power stations, effectively reducing Alberta's and Canada's greenhouse gas emissions.

After over a decade of preparation, our companies together with carefully selected partners are progressing the development of large-scale run-of-river hydro projects, including our proposed Slave River hydro project.

The 415-kilometre Slave River crosses the border between Alberta and the Northwest Territories and connects into Great Slave Lake. With a flow of approximately 4,000 cubic metres per second, it's a natural source of pure power.

The Slave River project is still in early stages and much work remains to be done with local peoples to study the impacts from an environmental, social and economic perspective. However, we are encouraged by the tremendous potential to capture emissions-free electrical generation and provide socio-economic benefits to the local communities.

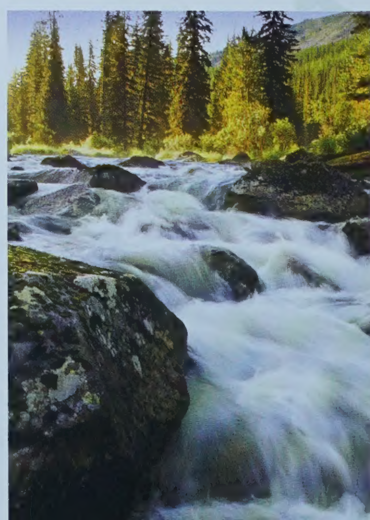
Should the Slave River hydro project become a reality, it would be used to produce emissions-free electricity for northern, central and southern Alberta; clean power fed through a network of new transmission lines proposed by the Government of Alberta.

In 2009, ATCO Electric was authorized by Alberta's Minister of Energy to prepare a facilities application to build and operate a new high-voltage, direct-current transmission line along an eastern corridor in Alberta. It will connect an area north of Edmonton to a southern hub in the Brooks area providing safe, reliable electrical service across the province.

As part of the facilities application, ATCO Electric will determine the exact route for the transmission line, consulting with, and considering impacts to, landowners, First Nations, communities and the environment.

By combining ATCO Electric's extensive experience in developing and constructing transmission infrastructures through rural Alberta with ATCO Power's hydro development experience, our Group is well positioned to carry out the Green Corridor program.

Together, the two companies are determined to help lead CU toward a new green energy frontier that focuses on sustainable power from north to south.



ATCO's Green Corridor begins in Canada's north with the development of hydro generation projects.

Business Segments

Canadian Utilities Limited is a diversified, Canadian-based, international group of companies focused on profitable sustainable growth and achievement with approximately $9.1 billion in assets and more than 5,700 people actively engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation and natural gas gathering, processing and storage and liquids extraction) and Technologies (business systems solutions).

Utilities

ATCO Electric   ATCO Gas   ATCO Pipelines

Energy

ATCO Power   ATCO Midstream   ATCO Energy Solutions

ATCO I-Tek   ATCO Travel

Companies Join Forces

In 2008, the Boards of Canadian Utilities Limited (CU) and ATCO Ltd. (ATCO) appointed special committees of independent directors to assess the potential acquisition of CU subsidiary, ATCO Frontec, by ATCO.

After extensive review and analysis by external financial and legal advisors, both the CU and ATCO special committees independently determined it would be in the best long-term financial interests of share owners to proceed with an amalgamation. The key reason: an amalgamation would create expanded business opportunities and improved operational efficiencies.

On July 1, 2009, CU and ATCO finalized an agreement to combine ATCO Frontec with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO. CU has a 24.5 per cent ownership interest in the newly formed company, ATCO Structures & Logistics (ASL).

The amalgamation and creation of ASL combines complementary knowledge and expertise into one company.

- The specialized expertise of the former ATCO Frontec was in the rapid mobilization and delivery of site support and camp services to the global resource, defence and telecommunications sectors.
- ATCO Structures' expertise was in manufacturing, selling and leasing workforce housing and modular buildings around the world.

PHOTO
ATCO Frontec Europe Ltd., a subsidiary of ATCO Structures & Logistics, specializes in providing camp and logistics services to the military, including airfield operations. It has partnered with NATO and non-government organizations to provide infrastructure services in some of the world's most challenging and remote environments.

- ATCO Noise Management was a leader in providing acoustical consulting services and turnkey noise control for industrial facilities.

As one company, ASL now offers customers innovative solutions and logistics support for facilities, catering, housing, construction and site management worldwide. The expanded size and expertise, combined with the wider range of business offerings, creates opportunities none of the three companies could achieve individually.

As a minority shareholder in ASL, CU entered into a shareholders' agreement with ATCO to establish a governance framework for the new company which provides CU with proportionate board representation and certain other rights with respect to share issuances and transfers.

Profits from the investment will be shown in CU quarterly and annual consolidated statement of earnings reports as "Earnings from investment in ATCO Structures & Logistics." CU share owners now own part of a much larger company with an expanded suite of products and services which can be focused to meet the changing needs of both traditional and new customers worldwide.

Utilities

ATCO ELECTRIC | ATCO GAS | ATCO PIPELINES

The Utilities business segment includes ATCO Electric, ATCO Gas and ATCO Pipelines. These companies are focused on the safe, reliable and efficient transportation and distribution of natural gas and electricity.

(ABOVE, LEFT TO RIGHT)

SETT POLICICCHIO
President, ATCO Electric

BRIAN HAHN
President, ATCO Gas

BRENDAN DOLAN
Senior Vice President & General Manager, ATCO Pipelines

PHOTO (LEFT)
Pipe rack at the ATCO Pipelines salt caverns natural gas storage facility and plant near Fort Saskatchewan. These facilities ensure natural gas service is available to all customers 365 days per year.

ATCO ELECTRIC

ATCO Electric builds, operates and maintains a safe, reliable network of transmission and distribution power lines to homes, farms and businesses in cities, towns and Aboriginal communities across Alberta. The company serves nearly 207,000 customers in 245 communities spanning 65 per cent of Alberta, with service areas in the northern and east-central areas of the province. These resource-rich areas play an essential role in Alberta's industrial development.

ATCO Electric operates and maintains nearly 70,000 kilometres of transmission and distribution power lines and operates approximately 12,000 kilometres of distribution power lines on behalf of Rural Electrification Associations (REAs). The company has been serving this challenging, diverse territory for more than 80 years.

In 2009, ATCO Electric was authorized to prepare a facilities application to build and operate a new high-voltage transmission line along an eastern corridor in Alberta. The line will connect an area north of Edmonton to a southern hub in the Brooks area.

The transmission infrastructure project coincides with the Alberta Electric System Operator's (AESO) Long-term Transmission System Plan. The transmission lines proposed in the plan will form the backbone of the transmission system for decades to come, providing reliable electricity service

for Albertans and supporting future economic development in the province. The transmission lines proposed in the AESO's plan calls for $8.1 billion in critical transmission infrastructure to be built over the next five years.

As a result of the extensive transmission infrastructure growth in Alberta, ATCO Electric continues to invest a significant amount of capital, totaling nearly half a billion dollars in 2009 alone. The company completed construction of the $185 million Brintnell-Wesley Creek 240 kilovolt transmission line, strengthening the electrical grid in northwest Alberta. This major 226-kilometre transmission project was commissioned in early 2010.

ATCO Electric continues to aggressively recruit new employees to support its growth. In 2009, the company hired 258 new employees to undertake the significant projects planned.

The Alberta utility industry's first hybrid maintenance vehicle was introduced by ATCO Electric in the Grande Prairie region. The new bucket truck operates on electricity and diesel, which lowers emissions by approximately 70 per cent and reduces fuel consumption by up to 60 per cent. While operating on electric power, the unit is significantly quieter than a standard diesel-powered bucket truck, producing up to 80 per cent less noise.

Ongoing technology and work process enhancements continued to improve how ATCO Electric operates its business. In 2009, ATCO Electric rolled out its new Work Force Management System and Outage Management System, improving efficiency and response time for customers. These new systems allow ATCO to improve work prioritization and better track outages. Implementation of these new processes will enable the company to provide exceptional customer service and enhance the company's pursuit of operational excellence.

PHOTO (BELOW)
ATCO's new hybrid maintenance vehicle.

North of 60 Companies

For more than a century the Canadian Utilities (CU) companies have been building mutually beneficial relationships with northern partners. CU's numerous partnerships have created many successful businesses. CU is committed to the North and believes in supporting the communities where we live and work.

Northland Utilities

Northland Utilities has been lighting up the North for more than half a century. Northland serves nine communities and the majority of customers in the Northwest Territories, including Yellowknife and Hay River. Northland Utilities is a full-service company providing retail, distribution, transmission and generation services to its customers. Northland Utilities has two operating divisions - Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

Yukon Electrical

The Yukon Electrical Company Limited has been providing electrical service to Yukoners for more than a century. Chartered in 1901, the pioneer company began generating electricity for the residents of Whitehorse using a wood-fired, horizontal piston steam engine. Since then, Yukon Electrical has grown to serve more than 15,000 customers in 19 communities from south of the Yukon border to north of the Arctic Circle. The company's head office and service centre is in Whitehorse.

In 2009, Yukon Electrical renewed its air emissions permit for its diesel-fired power plants for a further three years. The company also signed an agreement with the community of Old Crow to allow the use of residual heat from the Yukon Electrical power plant for heating of nearby residential buildings and a future recreational facility in the community.

PHOTO (RIGHT)
ATCO Electric Serviceman, Dean Fox, replaces a transformer near Vegreville.

ATCO GAS

ATCO Gas builds, operates and maintains a safe, reliable, and cost-effective network of natural gas distribution pipelines of nearly 38,000 kilometres and provides service to municipal, residential, business and industrial customers.

ATCO Gas is Alberta's largest natural gas utility serving more than one million customers in nearly 300 Alberta communities.

Strong natural gas utility asset growth continued in 2009, with capital expenditures of $190 million. The company expanded its fleet of operations centres, while raising the bar for sustainable building practices. ATCO Gas opened its Viking Operations Centre, equipped with geo-exchange heating technology that draws heat energy from the earth to reduce the company's environmental footprint. The new 518 square metre ATCO facility at Viking, Alberta includes heat-exchanger pipes installed into 14 bore holes drilled 61 metres deep. It also contains energy-efficient lighting, insulation and a high-efficiency water heater. The building has been designed to reduce carbon dioxide emissions on site by approximately 15 tonnes annually.

ATCO Gas and the City of Airdrie participated in a sod-turning ceremony to celebrate the start of construction of another ATCO Gas operations centre. The new building will be the first commercial geo-exchange facility in Airdrie and the third in Canada making use of natural gas-fueled pumps in its heating and cooling system. Scheduled to open in late fall 2010, the 1,400 square metre facility will use state-of-the-art geo-exchange technology, reinforcing ATCO Gas' pledge to minimize its environmental footprint.

Steady growth and demand in the Peace River Region also led to the opening of a spacious new operations centre in Peace River. The building was designed to better serve customers, reduce response time and optimize work flow, with room to grow.

The company also continued its multi-year Meter Relocation and Replacement Project. In addition to providing easier access to gas meters to ensure accurate, timely billing, the project improves safety for meter readers. Approximately 10,000 natural

PHOTO (BELOW)
ATCO Gas has the facilities and capabilities to better serve its customers in Viking and area through ATCO's new Viking Operations Centre.

gas meters were moved to the outside of homes in 2009 and most residential below-ground moves from inside to outside buildings are scheduled to be completed by the end of 2010.

Safety continues to be paramount for ATCO Gas. 2009 was the company's most successful year for damage prevention, with only 2.8 damages to natural gas lines per 1,000 locates. This represents a 22 per cent reduction in damages to natural gas lines from 2007 and a 45 per cent reduction since 2003. In the fall, the company also launched a province-wide campaign aimed at increasing meter reader safety and educating customers on carbon monoxide prevention.

ATCO Blue Flame Kitchen

The ATCO Blue Flame Kitchen has been dishing up household advice and recipes in the province of Alberta for 80 years. This provides ATCO Gas the unique opportunity to connect and engage directly with customers in their homes and offer energy efficiency, conservation and safety information. Over the years, the Blue Flame Kitchen has continued to promote the values of safety, efficiency and sustainability through regular newspaper and television spots, seasonal cookbooks, toll-free telephone advice, outreach activities and a website located at www.atcoblueflamekitchen.com.

In 2009, a Red Seal Chef was hired to offer a new area of expertise, provide advice on healthy eating for busy families and offer tips on cooking and kitchen safety.

ATCO EnergySense

ATCO EnergySense provides Albertans with energy efficiency advice and improvement services for their homes and businesses. Established in 2001 by ATCO Gas and ATCO Electric, ATCO EnergySense experts have handled more than 168,000 energy management requests and completed approximately 49,000 residential energy assessments, resulting in the potential reduction of more than 46,000 tonnes of greenhouse gas emissions annually.

PHOTO (RIGHT)
Bruce Legault, Supervisor, Customer Service, completes a furnace inspection to help prevent carbon monoxide in the home.

ATCO PIPELINES

ATCO Pipelines has been an integral part of Alberta's provincial natural gas transmission system for nearly a century, with peak delivery of 3.8 billion cubic feet per day. ATCO Pipelines' transportation customers can access the markets of their choice through the company's innovative, flexible and cost-effective transportation solutions.

ATCO Pipelines provides natural gas transportation services to producers, marketers, industrial customers and gas distribution companies in Alberta. It owns and operates 8,563 kilometres of pipeline with 190 receipt points and more than 4,000 delivery points.

As announced in 2008, ATCO Pipelines reached a proposed agreement with TransCanada Corporation's wholly-owned subsidiary, NOVA Gas Transmission Ltd. (NGTL), to integrate their service and systems in Alberta and has since proceeded with the necessary regulatory applications. As part of this process, ATCO Pipelines successfully negotiated a settlement for revenue requirements with customers for 2010-2012. In addition, ATCO Pipelines and NGTL have filed separate applications with their respective regulators, the Alberta Utilities Commission and the National Energy Board, to allow the two companies to proceed with a single commercial customer interface concept and begin the necessary transfer of assets.

Each company will manage its own pipeline facilities within distinct operating territories going forward. The two companies will request a satisfactory opinion under the provisions of the Competition Act. Once approved and implemented, this agreement will deliver seamless natural gas transmission service to customers throughout Alberta.

ATCO Pipelines' capital expenditures for 2009 were $87.7 million, including an expansion in southeast Calgary. This significant pipeline enhancement now provides increased gas service for upcoming housing developments in the area. Major directional drilling under roadways was required, including Deerfoot Trail at Highway 22X, to add nearly four

PHOTO (BELOW)
A transmission operator performs routine activities at the ATCO Pipelines South Calgary Control Station where the Priddis and South Mainline natural gas pipelines interconnect.

kilometres of 406 mm pipeline to the existing Priddis line in order to connect to ATCO Gas' new gate station. Several tie-ins were also completed and new measurement facilities were installed.

ATCO Pipelines replaced its Supervisory Control and Data Acquisition (SCADA) and real-time model (RTM) systems in 2009. The SCADA system is used to monitor and control flows in the gas transmission system to ensure the safe, reliable delivery of natural gas, while the RTM supports the SCADA system by providing additional information along the pipeline and is used to identify and forecast hydraulic system anomalies to help optimize pipeline design and operation.

PHOTO (RIGHT)
An ATCO Pipelines transmission operator inspects a rain cap on a pressure relief stack.

PHOTO (BELOW)
ATCO Pipelines owns and operates 8,563 kilometres of pipeline in Alberta.

Energy

ATCO POWER | ATCO MIDSTREAM | ATCO ENERGY SOLUTIONS

The Energy business segment includes ATCO Power, ATCO Midstream and ATCO Energy Solutions. These companies are engaged in power generation and natural gas gathering, processing, storage and liquids extraction.

(ABOVE, LEFT TO RIGHT)

RICK BROUWER
President, ATCO Power

KEVIN CUMMING
President, ATCO Midstream

TONY SALTERS
Vice President & General Manager, ATCO Energy Solutions

PHOTO (LEFT)
The water treatment facility at ATCO Power's Sheerness generating station near Hanna, Alberta, purifies water used for the generation of electricity.

ATCO POWER

ATCO Power is a world-class developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power generation plants in Canada, the United Kingdom and Australia.

With a combined capacity of approximately 4,885 megawatts (MW), ATCO Power operates 19 generating facilities: 16 facilities fueled by clean natural-gas, one emissions-free hydroelectric facility and two coal-fired plants.

In March 2009, ATCO Power celebrated the start of construction of its 20th generating facility. The new 86 MW power station in Karratha is the company's first project in Western Australia where significant new mining and oil and gas activity offer long-term growth opportunity.

The Karratha Power Station, owned and operated by ATCO Power, will supply electricity to residential and business consumers on the Pilbara North West Interconnected System (NWIS) under a long-term contract with state-owned Horizon Power. The station is directly adjacent to Horizon's 132 kilovolt Karratha Terminal giving it a direct link into the local network.

The project, located 1,600 kilometres north of Perth, is the most efficient gas-fired power station in the region. The Karratha Power Station is capable of generating the same amount of electricity as a similar sized station, yet uses 35 per cent less gas, reducing carbon dioxide emissions by

the same 35 per cent. Advanced technology also further reduces other pollutants such as nitrous oxide and sulphur dioxide.

The new station will have an initial capacity of 86 MW but it has been designed to allow for future expansion to meet growing needs in the area. Full operation is expected by the second quarter of 2010.

In Alberta, ATCO and TransCanada Corporation are exploring the opportunity to develop a hydroelectric project on the Slave River, near the Alberta-Northwest Territories border. The preliminary assessment phase confirmed the initial economic viability of a 1,000 – 1,500 MW low-head, run-of-river facility 20 kilometres south of the town of Fort Smith. ATCO and TransCanada are working with local communities to assess the project's environmental, social and economic feasibility.

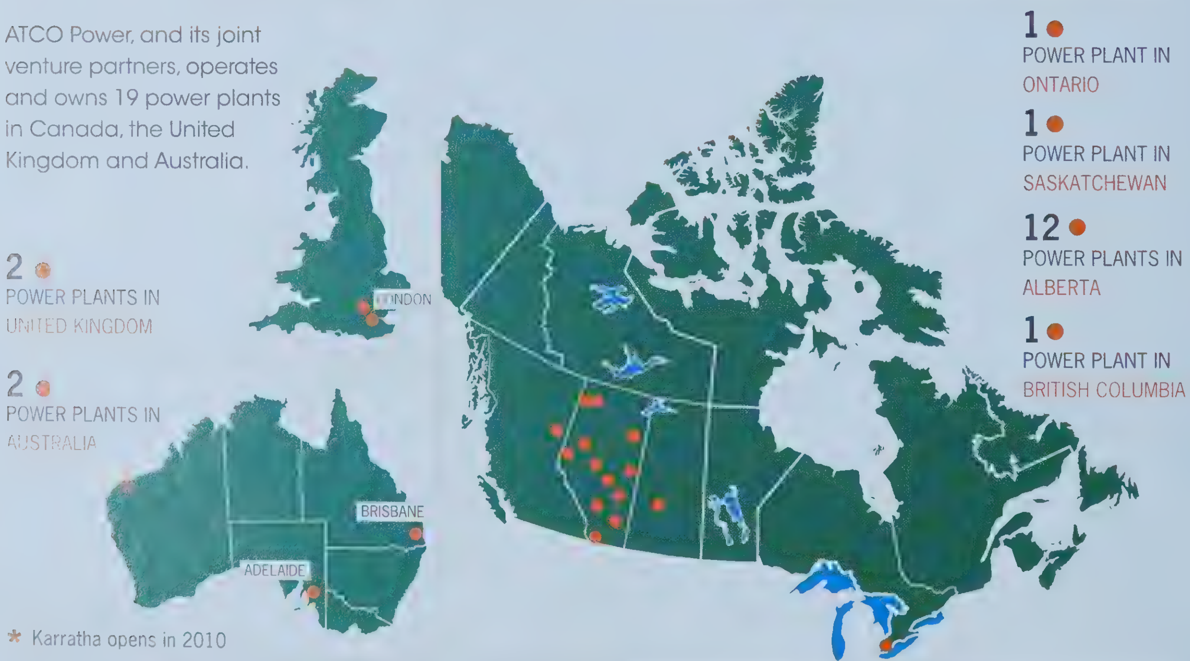
2009 was a challenging year for ATCO Power due to economic conditions in its markets. Alberta Power Pool electricity rates averaged $47.81 per megawatt hour (MWh) in 2009 compared to $89.95 per MWh in 2008. Lower natural gas prices and changes in the price of electricity resulted in an average Spark Spread of $19.58 per MWh in 2009, compared to $32.00 per MWh in 2008.

ATCO Power implemented a number of initiatives to address the changing market conditions, including cost reductions, improved operational efficiencies and a review and adoption of new industry best practices.

At the 480 MW co-generation facility in Joffre, Alberta, new operating procedures were tested and implemented to increase turn down capability of the steam turbine, optimizing asset performance

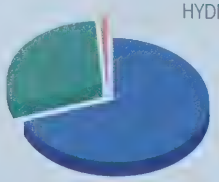
ATCO POWER – A Leader In Power Generation Worldwide

ATCO Power, and its joint venture partners, operates and owns 19 power plants in Canada, the United Kingdom and Australia.



* Karratha opens in 2010

ATCO POWER GENERATION PORTFOLIO



ATCO POWER GENERATING CAPACITY

	2009
Generating capacity operated (MW)	4,885
Generating capacity owned (MW)	2,503

during periods of low power prices. Intense focus on managing both planned and unplanned outages at facilities led to improved results.

In 2009, major preventive maintenance programs were undertaken in Alberta at CU's 670 MW Battle River Generating Facility in Forestburg and at the 760 MW Sheerness plant in Hanna. These programs are targeted at enhancing unit availability and efficiency.

In August, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering the Canada Revenue Agency to reverse its 2006 reassessment of Alberta Power's 2001 tax return. The 2006 reassessment treated the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than a sale of an asset. The impact of the judgment is a \$16.8 million increase in CU earnings and a refund of approximately \$28 million.

ATCO Power also actively participated in extensive consultation with the Alberta and Canadian governments, as well as other industry participants, regarding the development of environmental policy during the year that included regulations for greenhouse gas (GHG) emissions, nitrogen oxides, sulphur dioxide and particulate matter.

ASHCOR Technologies

ASHCOR markets the coal combustion products from ATCO Power's coal-fired generating stations in Alberta. By collecting the fly ash produced, and using it in new cementing materials, ASHCOR achieves two environmentally significant results: it captures a by-product that would normally go to a reclamation site and uses it in other construction material applications.

PHOTO (RIGHT)
ATCO Power's 20th power generating station in the world, the 86 MW Karratha Power Station in Western Australia will provide electricity supply and stability to the resource-intense region of Australia.

ATCO MIDSTREAM

ATCO Midstream provides natural gas gathering, processing, storage and liquids extraction to the Canadian natural gas sector. ATCO Midstream focuses on what it does best – creating customized solutions and lasting customer relationships by drawing on a proven track record and a partnership approach to business.

Since 1992, the company has played a significant role in the gas industry in Alberta and Saskatchewan. Assets include 10 natural gas gathering and processing facilities and four natural gas liquids extraction facilities. The company provides innovative natural gas storage services with more than 40 billion cubic feet of capacity available. It is active in Canada's North as a partner in the Inuvik Gas Project – the first natural gas development project north of the Arctic Circle.

2009 marked a year of record earnings, multiple expansion projects in Saskatchewan, and a company-wide focus on improving efficiencies to better serve customers.

In Alberta, the natural gas gathering and processing business was negatively affected by reduced year-over-year drilling activity in the province. To take advantage of increased business activity in Saskatchewan, ATCO Midstream participated in the expansion of the processing capacity of the Nottingham Gas Plant in southeastern Saskatchewan from 13 million cubic feet per day (mmcfd) to 18 mmcfd. ATCO Midstream's share of the expansion was 0.5 mmcfd, boosting the company's total capacity at the facility to 1.4 mmcfd.

The associated Wolstitmor Gathering System was also expanded when 13 kilometres of gathering pipelines and a compressor station were added to gather flared solution gas to the Nottingham Gas Plant.

Construction activities commenced in November 2009 to more than double the processing capacity at the Kisbey Gas Plant, located in southeastern Saskatchewan. A 50-50 joint-venture with Bayhurst Energy Services Corporation, capacity will be increased from two to five mmcfd, and 80 kilometres of new gathering pipelines and three compressor

stations will be added. The expansion will be commissioned in 2010. The expansion gathers flared solution gas in order to conserve and upgrade a valuable non-renewable resource.

ATCO Midstream also carried out a major initiative to improve efficiencies to deliver improved value to customers. With most costs traditionally flowing directly through to customers, the line-by-line, plant-by-plant effort allowed the company to increase its long-term competitive position while delivering increased benefits to the customers it serves.

It was also a very strong year for natural gas storage at the Carbon facility in Alberta. Natural gas prices were volatile, resulting in stronger than normal storage differentials.

ATCO Midstream owns a net working interest of 411 mmcfd of processing capacity in its natural gas liquids extraction plants. In 2009, low frac spreads (the difference between the price of natural gas and the value of the liquids extracted) had a negative impact compared to 2008 when the spreads were higher.

The company also focused on sustainable energy projects. ATCO Midstream achieved greenhouse gas reductions at several facilities through a company-wide fuel gas reduction initiative. One example was the installation of a more energy-efficient heater at the Golden Spike facility in Alberta resulting in a greenhouse gas (GHG) emissions reduction of 370 tonnes of CO_2 equivalent per year.

PHOTO (LEFT)
ATCO Midstream is an owner and the operator of the Empress Gas Liquids Joint-Venture Straddle Plant. The facility extracts natural gas liquids from the gas on the TransCanada Pipelines Alberta system as the gas crosses the Alberta-Saskatchewan border near Empress, Alberta.

PHOTO (RIGHT)
An employee at the Empress Gas facility is caught in the sunset as he makes his way down a ladder.

ATCO ENERGY SOLUTIONS

ATCO Energy Solutions offers value-added infrastructure solutions to both municipal and industrial customers, including pipelines, water and wastewater treatment, and hydrocarbon storage, including hydrogen.

In 2009, ATCO Energy Solutions focused on building, owning and operating non-regulated electric transmission assets and executing on its pipeline, storage and water initiatives.

Growth in heavy-oil processing in Alberta will create an increased demand for hydrogen, which is used to remove sulphur to achieve cleaner-burning end-product fuels and to meet environmental standards. In 2009, ATCO Energy Solutions and Praxair Canada Inc. announced they are pursuing the development of hydrogen storage and pipeline infrastructure. They are also assessing an expansion of Praxair's hydrogen pipeline network in the Alberta Industrial Heartland to support the significant projects planned for the area.

PHOTO (BELOW)
ATCO Energy Solutions commissioned a new substation in 2009 that will provide power to an expansion of the Scotford upgrader near Fort Saskatchewan, Alberta.

Currently, Praxair owns and operates the only existing hydrogen pipeline network in Alberta.

Throughout 2009, ATCO Energy Solutions installed and commissioned new power transmission and substation equipment at the Scotford industrial complex near Fort Saskatchewan, Alberta. The company also acquired power transmission facilities at the Muskeg River and Jackpine Mine sites north of Fort McMurray this past year.

ATCO Water

ATCO Water, a division of ATCO Energy Solutions, focuses on building, owning and operating water and wastewater infrastructure and facilities for industrial and municipal customers.

In 2009, ATCO Water was selected by the towns of Three Hills and Trochu to develop a long-term partnership for the delivery of regional water and wastewater services. Under the proposed partnership, ATCO Water would purchase a minority ownership interest in the integrated water and wastewater systems of both communities, manage the merged operations, and provide capital for future infrastructure.

ROBERTA (BOBBI) LAMBRIGHT
President, ATCO I-Tek

PHOTO ATCO I-Tek produces and delivers approximately 11.8 million customer statements for energy and utility clients every year.

ATCO I-TEK

ATCO I-Tek delivers exceptional billing flexibility, superior customer care, and reliable information technology solutions to a diverse group of clients that operate in Canada, the United States, and around the world. Headquartered in Edmonton, it is a disciplined business-to-business service provider with proven processes and controls.

In 2009, ATCO I-Tek and ATCO Group Human Resources implemented HRXcellence across the group of companies. It marked the culmination of two years of work by people from each of Canadian Utilities' (CU) principal operating subsidiaries.

HRXcellence represents a significant investment in the future of CU's people as it provides a modern human resource and payroll management system to sustain and grow CU's businesses in the future. The initiative ensures that CU can meet the unique needs and complexities of each of its companies. HRXcellence will allow CU's operating companies to better manage all aspects of employee resources and it enables new possibilities for employee career development and inter-company movement.

In 2009, clients of ATCO I-Tek benefited from the implementation of software to leverage the use of common data and functionality across multiple business systems. This real-time integration allows businesses to operate more efficiently with more timely, accurate information.

For example, CU's utility companies, ATCO Gas and ATCO Electric, are able to leverage data and functionality across three major business systems. The Customer Information System billing system shares site information with the ATCO Gas Work Management and the ATCO Electric Work Force Management Systems. This means that front-line service personnel serving customers on-site and customer care staff answering calls are able to use current, consistent data to serve customer needs from end-to-end in a timely fashion.

In 2009, ATCO I-Tek's Customer Support Centre handled in excess of 81,000 IT client requests and achieved a customer satisfaction rating of 97 per cent for problem resolution.

ATCO I-Tek also entered into a strategic partnership with Wipro, a business process outsourcing organization to provide delivery of call centre services. This partnership gives ATCO I-Tek the ability to access an international service delivery centre, effectively expanding service delivery to enhance competitiveness and offer more flexibility to clients.

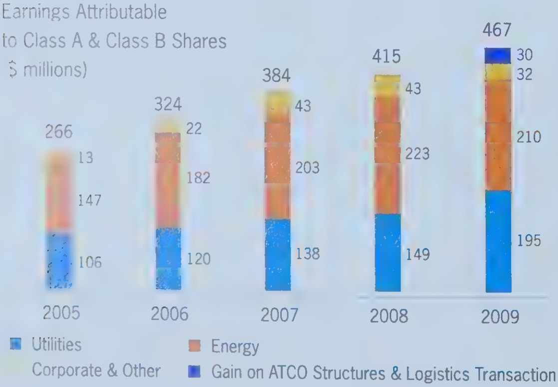
Financial Excellence 2009

Brian R. Bale
Senior Vice President &
Chief Financial Officer

Canadian Utilities' record earnings in 2009 of $466.6 million ($3.71 per share), an increase of 13% compared to 2008, were attributable to cost efficiencies throughout the organization, higher utility investment in rate base and the gain on the ATCO Structures & Logistics transaction. Canadian Utilities' adjusted earnings in 2009 were $427.6 million ($3.40 per share) compared to $403.2 million ($3.21 per share) in 2008.

Due to the diverse nature of Canadian Utilities' operations and inclusion in revenues of certain costs that are flow through in nature (particularly natural gas), changes in revenues are not necessarily indicative of changes in earnings. Revenues in 2009 were $2,584.0 million compared to $2,778.9 million in 2008.The decrease is primarily due to the impact of the ATCO Structures & Logistics transaction, lower power prices in the Alberta electricity market, lower U.K. exchange rates and lower NGL prices and volumes in the Energy segment. Changes in accounting for rate regulated operations and lower sales of natural gas purchased for third parties by ATCO Midstream also decreased revenues but did not impact earnings. The decreases were partially offset by the impact of increased rate base in ATCO Electric and ATCO Gas and higher storage revenues in ATCO Midstream.

Earnings Attributable
to Class A & Class B Shares
($ millions)



CONSOLIDATED HIGHLIGHTS	2009	2008
(Millions of Canadian dollars, except as indicated)		
INCOME STATEMENT		
Revenues	**2,584.0**	2,778.9
Earnings		
Utilities	**195.4**	148.6
Energy	**209.5**	223.0
Corporate & Other and Eliminations	**61.7**	42.9
Earnings	**466.6**	414.5
Adjusted earnings (1)	**427.6**	403.2
BALANCE SHEET		
Cash (2)	**796.0**	726.6
Total Assets	**9,083.6**	7,860.0
Capitalization		
Long Term Debt	**3,102.3**	2,844.3
Non-recourse Long Term Debt	**354.8**	412.4
Equity Preferred Shares	**785.0**	625.0
Share Owners' Equity	**3,046.1**	2,748.5
Capitalization	**7,288.2**	6,630.2
CASH FLOW STATEMENT		
Funds Generated by Operations (3)	**793.4**	796.5
Capital Expenditures		
Utilities	**776.1**	852.6
Energy	**151.5**	109.7
Corporate & Other	**18.5**	48.6
Capital Expenditures	**946.1**	1,010.9
RATIOS		
Return on equity (%)	**16.1**	15.7
Earnings per share ($)	**3.71**	3.30
Adjusted Earnings per share ($) (1)	**3.40**	3.21
Dividends paid per share ($)	**1.41**	1.33
Equity per share ($)	**24.20**	21.90
Class A Non-Voting closing share price ($)	**43.75**	40.50
Class B Voting closing share price ($)	**43.77**	40.00

Full disclosure of all financial information is available on the SEDAR website - www.sedar.com.

(1) Adjusted earnings are defined as earnings attributable to Class A and Class B shares after adjustment for items that are not in the normal course of business nor a result of day to day operations. The adjustments in 2009 related to the gain on ATCO Structures & Logistics transaction ($29.6 million), H.R. Milner tax reassessment ($16.8 million) and mark-to-market adjustment ($7.4 million). This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies. For further information please see the Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section of Canadian Utilities Limited's Managment's Discussion and Analysis.

(2) Cash is defined as cash and short-term investments less bank indebtedness.

(3) Funds generated by operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

Canadian Utilities Limited

CONSOLIDATED FIVE-YEAR OPERATING SUMMARY

(Millions of Canadian dollars, except as indicated)	2009	2008	2007	2006	2005
UTILITIES					
Natural gas distribution operations					
Capital expenditures (1)	**189.6**	249.7	191.6	167.4	174.0
Pipelines (thousands of kilometres)	**37.7**	37.2	36.5	35.9	35.4
Maximum daily demand (terajoules)	**2,184**	2,130	1,819	1,861	1,919
Natural gas distributed (petajoules)	**250**	238	233	219	216
Total system throughput (petajoules)	**250**	238	233	219	216
Average annual use per residential customer (gigajoules)	**121**	124	127	126	131
Customers at year-end (thousands)	**1,037.4**	1,022.2	1,001.8	969.9	939.6
Electric distribution and transmission operations					
Capital expenditures (1)	**497.8**	518.4	311.8	238.1	212.2
Power lines (thousands of kilometres)	**72.1**	71.5	70.9	70.1	69.2
Electricity distributed (millions of kilowatt hours)	**10,431**	10,594	10,744	10,286	9,926
Average annual use per residential customer (kWh)	**7,671**	7,666	7,690	7,495	7,214
Customers at year-end (thousands)	**233.1**	228.2	223.0	216.3	210.9
Natural gas transmission operations					
Capital expenditures (1)	**87.7**	81.7	87.1	97.7	84.3
Pipelines (thousands of kilometres)	**8.6**	8.4	8.4	8.4	8.3
Contract demand for pipelines system access (terajoules/day)	**4,877**	5,034	5,143	5,032	4,830
ENERGY					
Capital expenditures (1), (2)	**151.5**	109.7	56.7	54.0	43.4
Generating capacity operated (megawatts)	**4,885**	4,885	4,840	4,840	4,840
Generating capacity owned (megawatts)	**2,503**	2,503	2,467	2,474	2,474
Availability (%)	**94.9**	93.5	91.6	93.0	92.5
Natural gas processed (Mmcf/day)	**401**	435	478	480	476
Natural gas gathering lines (kilometres)	**1,000**	1,000	1,000	1,000	1,000

(1) Includes purchases of property, plant and equipment and intangibles.
(2) Prior year amounts restated to reflect the realigned segments.

Cash ($ Millions)

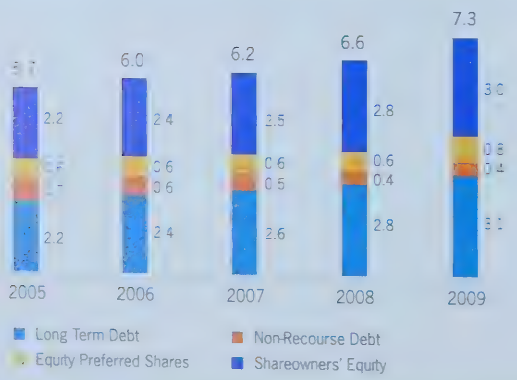
Canadian Utilities' balance sheet remains strong and positions the company for future growth. Cash balances (as defined on page 26) of close to $800 million have remained relatively consistent for the last five years. This has occurred in a year in which capital expenditures were close to $1 billion. Significant investments in Utility infrastructure are expected to continue from 2010 to 2012.

Funds Generated by Operations ($ Millions)

Funds generated by operations decreased to $793 million in 2009 compared to $797 million in 2008. This decrease was primarily attributable to lower availability incentives.

Capital Expenditures ($ Millions)

Canadian Utilities' capital expenditures for 2009 were $946 million compared to $1,011 million in 2008 reflecting the continued significant investments that were primarily attributable to the Utilities Segment. While 2009 capital expenditures in the Utilities Segment remain high by historic standards, a reduction from 2008 was experienced in natural gas distribution capital due to the economic slowdown in Alberta. Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.4 billion in 2010. Capital expenditures for the Utilities operations for 2010 to 2012 are expected to be $3.5 billion to $4.5 billion.



Capitalization ($ Billions)

Canadian Utilities share owners' equity at the end of 2009, including equity preferred shares, was $3.8 billion compared to $3.4 billion in 2008. The Corporation's non-recourse debt has been reduced over the last five years to $0.4 billion in 2009 from $0.7 billion in 2005.

Operating Expenses as a Percentage of Revenues (%)

Operating expenses (which include natural gas supply, purchased power, operation and maintenance, selling and administration expenses and franchise fees) as a percentage of revenues decreased to 57% in 2009 compared to 59% in 2008 as a result of focused efforts on cost control throughout the Corporation.

Return on Equity (%)

Return on equity (ROE) for 2009 was 16.1% compared to 15.7% in 2008. Higher equity has been maintained for the Corporation to fund the significant investments in the Utilities infrastructure that are expected from 2010 to 2012. The 16.1% ROE was achieved even with the Utilities approved ROE of 9.0% for 2009. Therefore, the overall ROE was driven by efficiencies and the results of the non-regulated entities in the Corporation.

Dividends per Share ($)

Dividends paid to common shareowners were $1.41 per share in 2009 compared to $1.33 per share in 2008. Excluding the impact of the special dividend in 2006, dividends per share have increased each year since 1972 - 37 years.

Share Price ($)

The price of Canadian Utilities Class A and Class B shares, on the Toronto Stock Exchange, increased from the 2008 closing price. The closing prices for Class A and Class B shares at the end of 2009 were $43.75 and $43.77 respectively compared to $40.50 and $40.00 at the end of 2008, increases of 8% and 9% respectively.

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian Generally Accepted Accounting Principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Corporation's internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Corporation's operating, reporting and risk management activities.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

N.C. South

N.C. Southern
Deputy Chair, President & Chief Executive Officer

B.R.Bale

B.R. Bale
Senior Vice President & Chief Financial Officer

February 17, 2010

Health and Safety

Canadian Utilities' (CU) unwavering commitment to excellence in health and safety practices was demonstrated by numerous awards the CU companies received in 2009.

ATCO Pipelines, ATCO Midstream, ATCO Power and ATCO Noise Management (now ATCO Structures & Logistics) were recognized by the Government of Alberta and the Alberta Occupational Health and Safety Council for superior health and safety records. It was the fifth consecutive year that ATCO Power was recognized by the province for its safety practices and the sixth consecutive year for ATCO Pipelines.

At ATCO Power's Sheerness Generating Station, the dedication and commitment of employees to safety resulted in 3.1 million hours—or approximately nine years—worked without a lost-time injury. The safety achievement is significant considering the plant is a heavy industrial setting that presents everyday challenges to most of the 122 ATCO Power employees and contractors.

The North of 60 companies had an outstanding year in 2009 related to health and safety. Northland Utilities (Yellowknife), Northland Utilities (NWT) and The Yukon Electrical Company each achieved a record of zero lost-time incidents.

PHOTO
The ATCO Power Sheerness Safety Committee salutes 3.1 million hours worked—or approximately nine years—without a lost-time injury.

Achieving a world-class safety culture is a continuing priority for ATCO Electric. In 2009, the company introduced a new safety campaign focused on the dangers of over-height farm equipment. ATCO Electric participates with Alberta's other major utility companies in the Joint Utility Safety Team to deliver Where's the Line powerline safety program. The company also introduced the Safety First, Always Program while achieving a new safety record of six months without a lost-time injury.

In 2009, safety continued to be paramount for ATCO Gas. ATCO Gas employee Terry Emslie, lead for the ATCO Gas Edmonton Damage Prevention group and a 28-year veteran with the company, received the Canadian Gas Association (CGA) Safety Leadership Award for his tireless commitment to the safety of fellow employees and the general public. The CGA's annual award recognizes individuals who make significant contributions to employee or public safety relating to the natural gas distribution industry in Canada.

Terry's damage prevention efforts were also recognized by ATCO Gas when he received the prestigious ATCO Gas Award of Excellence. Each year, this award goes to one ATCO Gas employee who shows outstanding achievement.

ATCO Celebrates Excellence

Celebrating Excellence was the largest and most comprehensive youth development initiative ever undertaken by ATCO, and was intended to reflect the long-standing commitment to the communities where our people work and live.

ATCO, Canadian Utilities' (CU) parent company, reached out to every corner of Alberta in 2009 with a program to encourage more than 400,000 Alberta students to think about leadership and making a difference in their communities.

The Celebrating Excellence program, launched in the fall, resulted in 166 Alberta students being awarded a trip of a lifetime to the 2010 Winter Olympics in Vancouver. A boy and a girl, along with a parent or guardian, from every provincial Alberta constituency received the opportunity to build Olympic dreams while cheering on Canada's sports heroes in Vancouver. Another 83 students won the runner-up prize of a laptop computer.

The students, in Grades 4 through 12, submitted short compositions explaining how they pursue leadership in sports, arts, culture, education or community involvement.

ATCO received thousands of entries from young Albertans who care deeply about enhancing the quality of life in their communities and striving for excellence in their everyday lives. Entries included stories such as how they are contributing time

PHOTO (BELOW)
One group of student winners (and their guardians) in Vancouver for their day at the Olympics.

to charities, volunteering in their communities, helping older neighbours and reaching out to immigrant newcomers.

The province-wide youth leadership initiative was undertaken in partnership with the Government of Alberta through its Olympic and Paralympic Secretariat. The Government of Alberta provided access to the tickets to Olympic sport and celebration events.

Students enjoyed an awe-inspiring day in Vancouver and came home with life-long memories. In addition to taking in an Olympic sport event, they were guests of the Government of Alberta at Alberta House in downtown Vancouver.

Celebrating Excellence was the largest and most comprehensive youth development initiative ever undertaken by ATCO, and was intended to reflect the long-standing commitment to the communities where our people work and live.

PHOTO (RIGHT)
Edmonton Celebrating Excellence winner, Kurtis Steendam, and his father Ralph, enjoy their day together at the Olympics in Vancouver.

PHOTO (BELOW)
David Chiu, a Celebrating Excellence winner from Calgary, shows off his patriotism at the Olympics.

Investing in our Communities

Canadian Utilities (CU) and its people participated in the ATCO Employees Participating in Communities (EPIC) program, which raised $2.7 million for more than 500 charities in our communities in 2009. It was an increase of $400,000 over the previous year.

The program is a unique fundraising initiative where employees donate to the charity of their choice. Their donations to human health and wellness are then matched by the company. The company also absorbs all administration costs, ensuring that 100 per cent of the funds go directly to benefiting organizations.

It is encouraging that even at a time of economic uncertainty, the people of CU opened their hearts and wallets and gave generously so others can benefit. This compassion and sense of giving is a hallmark of the people of CU.

Other initiatives included:

In 2009, ATCO Electric established the Fort Vermilion Travelling Trades partnership with Fort Vermilion School Division. The company also co-hosted two community symposiums with ATCO Gas and the towns of Trochu and Viking benefiting local non-profit and community-services organizations.

ATCO Electric helped fund construction of the Demmitt Cultural Society Sustainable Community Centre and a new spray park in Gooseberry Provincial

PHOTO (BELOW)
Edmonton employees celebrating the tremendous success of the ATCO Employees Participating in Communities (EPIC) fundraising program (from left): Tami Christensen, ATCO Structures & Logistics; Rose Herman, ATCO Pipelines; Alastair Hill, ATCO Power; Lorinda [illegible]ffrey, ATCO Electric; Mariann McPherson, ATCO I-Tek; Greg [illegible]ust, ATCO Structures & Logistics.

Park near Oyen. ATCO Electric and ATCO Gas helped "edu-tain" more than 20,000 students across Alberta with its highly entertaining ATCO Energy Theatre safety education program Superpower!.

ATCO Electric, ATCO Pipelines and ATCO Gas also helped deliver the children's activities program for Edmonton's annual National Aboriginal Day festival held at the Alberta Legislature grounds.

ATCO Gas continued its 20-year support of the Alberta Games in 2009, sponsoring torch runs and opening ceremonies for both the 55+ Winter Games and 55+ Summer Games held in Lethbridge and Airdrie respectively. The company also supported several Days of Caring events where company employees delivered a day of community service in support of the Okotoks-Foothills Hospice, the Jasper-Alpine Summit Lodge, Raymond-Stampede grounds, St. Albert's hosting of the Alberta Summer Special Olympics, playground construction in Blackfalds and community beautification efforts in the City of Brooks.

The ATCO Power Sheerness Power Plant near Hanna, Alberta supported the Red Deer River Watershed Alliance, an environmental initiative for proper watershed management. ATCO Power sponsored a youth gathering and cultural awareness event for the Piikani Nation. The company supported the University of Calgary Mentorship program, Days of Caring charity events in Calgary and Edmonton, Habitat for Humanity, community park painting and clean-up, the Mustard Seed and Goodwill.

ATCO Group sponsored Class Act, recognizing outstanding high school students from the Calgary area who achieved academic and extra-curricular success in 2009. It was the 20th anniversary of the event with ATCO in its fifth year of involvement.

ATCO I-Tek continued to donate equipment to Computers for Schools and other organizations in our communities to reduce the impact on the environment by keeping equipment out of landfills. More than 9,600 pieces have been donated since 2000.

PHOTO (RIGHT)
ATCO Gas sponsored The 2009 Alberta 55+ Summer Games in Airdrie. The ATCO Gas Torch Relay saw residents of Airdrie carry the Games' Flame to the Opening Ceremonies for the lighting of the Cauldron.

Commitment to the North

Canadian Utilities (CU) has enjoyed a long history with the people of Canada's North, building mutually beneficial, long-term relationships. This commitment was bolstered in 2009 with a series of new initiatives and a pledge to extend longstanding associations with northern communities and Aboriginal groups.

In 2009, Northland Utilities renewed its commitment to First Nations communities of Fort Providence, Trout Lake and Wekweti in the Northwest Territories to involve communities in operations plans. The partnerships provide training and another source of income in the community.

ATCO Power made a contribution toward infrastructure in Fort Smith to support the Slave River Hydro Development, while Yukon Electrical and ATCO Power signed a five-year agreement with Whitehorse Cross-Country Ski Club to provide company-owned property for ski trails.

In 2009, ATCO Group sponsored the 40th annual Circumpolar Games in Inuvik, Northwest Territories, a longstanding and important traditional gathering for those who live in the land of the midnight sun. The town of Inuvik and volunteers from the ATCO Midstream NWT team hosted more than 3,500 people from across the Arctic Circle. People came from Alaska, Northwest Territories and Nunavut, with many flying in from the most remote regions.

ATCO Group sponsors the Arctic Leadership Program annually that provides wilderness programming for young people within the Inuvialuit Settlement Region. The goal is the development of teamwork and personal life management skills, an increase in self-confidence and resilience, and to foster a sense of responsibility for one's actions — the hallmarks of strong leadership. The program exposes youth to different career options to develop an appreciation for the benefits of staying in school.

The company also sponsors five scholarships each year at Aurora College in Inuvik where the majority of students are Aboriginal. Aurora College serves a population dispersed across 33 communities in the Northwest Territories, delivering programs and courses through a network of three regional campuses as well as Community Learning Centres.

PHOTO (BELOW)
ATCO Group sponsored the Circumpolar Games in Inuvik, Northwest Territories, in 2009. Events included the sights and sounds of traditional Drum Dancing ceremonies.

High Prairie Emergency Training Centre

Four Canadian Utilities (CU) companies provide support for a much-needed fire-rescue training centre in Alberta's northwest.

The ATCO High Prairie Fire-Rescue Society Emergency Training Centre will provide hands-on and practical training for emergency rescue personnel throughout northwestern Alberta. Along with contributing financially to the centre, ATCO Electric, ATCO Gas, ATCO Power and ATCO Midstream will provide training support in the area of electrical and gas related emergencies. The training centre, scheduled to open in 2012, will improve the region's firefighting and emergency-response capabilities, helping to enhance the safety of residents in northwestern Alberta.

PHOTO (ABOVE)
ATCO cheque presentation for the High Prairie Emergency Training Centre. (Front row from left): Barry Johanneson, ATCO Gas, Manager Grande Prairie region; Neil McCagherty, ATCO Midstream, Operations Manager St. Albert; Bill Heighington, ATCO Electric, North East Regional Manager; Lynne Pardell, Deputy Fire Chief, High Prairie Fire Department; Melvin Beaudette, District Manager, High Prairie and member of the High Prairie Fire Department; Ken Melnyk, Chief, High Prairie Fire Department. (Back row from left): Trevor Cisaroski, Assistant Fire Chief, High Prairie Fire Department; Ron Gaudet, ATCO Electric, Powerline Technician Team Lead-Service; Joel Grassmick, ATCO Power, Turbine Operator Valleyview Generating Plant; Kevin Laing, ATCO Electric, Acting District Manager High Prairie.

Canadian Utilities Limited

Directors

Robert T. Booth, Q.C.
Partner, Bennett Jones LLP

Loraine M. Charlton
Corporate Director

David A. Dodge, O.C., LL.D., Ph. D., F.R.S.C.
Corporate Director

Denis M. Ellard
Corporate Director

Linda A. Heathcott
President & Chief Executive Officer
Spruce Meadows

Robert J. Normand
Corporate Director

Robert J. Routs, Ph. D.
Corporate Director

James W. Simpson
Corporate Director &
Lead Director

Nancy C. Southern
Deputy Chair, President &
Chief Executive Officer
Canadian Utilities Limited

Ronald D. Southern, C.B.E., C.C., LL.D.
Chairman of the
Board of Directors
Canadian Utilities Limited

Roger J. Urwin, C.B.E., Ph. D.
Corporate Director

Charles W. Wilson
Corporate Director

Officers

Ronald D. Southern
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Nancy C. Southern
Deputy Chair, President &
Chief Executive Officer

Siegfried W. Kiefer
Managing Director, Utilities

Brian R. Bale
Senior Vice President &
Chief Financial Officer

Robert J. (Bob) Myles
Senior Vice President, Corporate
Development & Planning

Susan R. Werth
Senior Vice President &
Chief Administration Officer

Erhard M. Kiefer
Group Vice President, Human
Resources & Corporate Services

Scott J. Garvey
Chief Information Officer

Carson J. Ackroyd
Vice President, Marketing &
Communications

Donald E. Belsheim
Vice President, Operational Audit

Ian D. Hargrave
Vice President,
Project Development

Kevin P. Hunt
Vice President, Risk & Pension

Robert C. (Rob) Neumann
Vice President, Internal Audit

Patricia (Pat) Spruin
Vice President, Administration &
Corporate Secretary

Catherine M. Widdoes
Vice President, HR Services

Paul G. Wright
Vice President, Finance,
Controller & Treasurer

Carol Gear
Assistant Corporate Secretary

Presidents and Senior Executives of Principal Operating Subsidiaries

Richard J. (Rick) Brouwer
President, ATCO Power Ltd.

Kevin J. Cumming
President, ATCO Midstream Ltd.

Brian R. Hahn
President, ATCO Gas

Roberta L. (Bobbi) Lambright
President, ATCO I-Tek Inc.

Settimio F. (Sett) Policicchio
President, ATCO Electric Ltd.

Joseph J. (Joe) Schnitzer
President, ASHCOR
Technologies Ltd.

Brendan G. Dolan
Senior Vice President &
General Manager,
ATCO Pipelines

Anthony J. (Tony) Salters
Vice President &
General Manager,
ATCO Energy Solutions Ltd.

Canadian Utilities Limited Organization Chart

Sustainability Report

ATCO Group published its first corporate Sustainability Report in 2009 that consolidates key data from nine diverse principal operating subsidiaries with more than 7,500 employees. Information on ATCO's sustainability initiatives and impacts is now contained in one document that covers the performance year ended December 31, 2008. It was prepared with the best information available and will be used as a basis point for further measurement in coming years.

You can view ATCO's Sustainability Report at www.atco.com.

PHOTO (BELOW)
ATCO is committed to creating healthy, vibrant communities where we live and work. We support hundreds of community endeavours through both financial contributions and the volunteer efforts of our employees.

General Information

Incorporation
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

Annual Meeting
The Annual Meeting of Share Owners will be held at 10:00 a.m. on Thursday, May 6, 2010 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

Auditors
PricewaterhouseCoopers LLP
Calgary, Alberta

Counsel
Bennett Jones LLP
Calgary, Alberta

Transfer Agent and Registrar
Class A non-voting and
Class B common shares and
Second Preferred
(Series W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

Trustee and Registrar
Debentures
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

Stock Exchange Listings
Class A non-voting Symbol CU
Class B common Symbol CU.X
Listing: The Toronto Stock Exchange
Cumulative Redeemable Second Preferred Shares
5.80% Series W Symbol CU.PR.A
6.00% Series X Symbol CU.PR.B
Listing: The Toronto Stock Exchange

ATCO Group Annual Reports
Annual Reports to Share Owners and Financial Information (Consolidated Financial Statements & Management's Discussion and Analysis) for ATCO Ltd. and Canadian Utilities Limited are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
Corporate Office
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.atco.com
www.canadian-utilities.com

Share Owner Inquiries
Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Telephone: 1-800-387-0825
Outside of North America: +1 (416) 643-5500
Fax: (416) 643-5501
Website: www.cibcmellon.com

Printed in Canada

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CANADIAN UTILITIES LIMITED
An ATCO Company

1400, 909-11th Avenue SW Calgary, Alberta T2R 1N6
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www.canadian-utilities.com

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CANADIAN UTILITIES LIMITED
An ATCO Company

2009

Financial Information

2009 Financial Information

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2009

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Corporation's internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Corporation's operating, reporting and risk management activities.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

N.C. South

N.C. Southern
Deputy Chair, President & Chief Executive Officer

B.R.Bale

B.R. Bale
Senior Vice President & Chief Financial Officer

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2009 and 2008 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2009. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 17, 2010

Canadian Utilities Limited
Consolidated Statement of Earnings and Retained Earnings
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31 2009	Three Months Ended December 31 2008	Year Ended December 31 2009	Year Ended December 31 2008
		(Unaudited)			
Revenues	1	**$ 675.6**	$ 744.3	**$2,584.0**	$2,778.9
Costs and expenses					
Natural gas supply		**4.3**	3.6	**23.2**	37.9
Purchased power		**14.3**	14.9	**54.1**	54.1
Operation and maintenance		**233.5**	300.4	**965.5**	1,123.5
Selling and administrative		**80.2**	87.2	**258.7**	244.8
Depreciation and amortization	1	**80.4**	100.1	**329.7**	387.2
Interest	7, 14	**60.7**	60.3	**241.6**	233.5
Franchise fees		**43.9**	42.5	**163.5**	175.2
		517.3	609.0	**2,036.3**	2,256.2
		158.3	135.3	**547.7**	522.7
Gain on ATCO Structures & Logistics transaction	4	**-**	-	**33.9**	-
Earnings from investment in ATCO Structures & Logistics	4	**4.1**	-	**7.8**	-
Interest and other income	6	**9.6**	14.6	**43.3**	59.1
Earnings before income taxes		**172.0**	149.9	**632.7**	581.8
Income taxes	7	**34.1**	27.2	**125.4**	134.8
		137.9	122.7	**507.3**	447.0
Dividends on equity preferred shares		**10.8**	8.2	**40.7**	32.5
Earnings attributable to Class A and Class B shares	1	**127.1**	114.5	**466.6**	414.5
Retained earnings at beginning of period as restated	8	**2,485.8**	2,206.3	**2,279.1**	2,031.4
		2,612.9	2,320.8	**2,745.7**	2,445.9
Dividends on Class A and Class B shares		**44.3**	41.7	**177.1**	166.8
Retained earnings at end of period		**$2,568.6**	$2,279.1	**$2,568.6**	$2,279.1
Earnings per Class A and Class B share	17	**$ 1.01**	$ 0.91	**$ 3.71**	$ 3.30
Diluted earnings per Class A and Class B share	17	**$ 1.01**	$ 0.91	**$ 3.71**	$ 3.29
Dividends paid per Class A and Class B share	17	**$ 0.3525**	$ 0.3325	**$ 1.41**	$ 1.33

Canadian Utilities Limited
Consolidated Balance Sheet

(Millions of Canadian Dollars)

	Note	December 31 2009	2008
ASSETS			
Current assets			
Cash and short term investments	21	**$ 796.0**	$ 748.6
Accounts receivable		**366.4**	385.5
Inventories	9	**79.8**	109.3
Income taxes recoverable	7	**8.5**	-
Future income taxes	7	**6.6**	5.9
Regulatory assets	1, 2	**37.4**	55.8
Derivative assets	24	**1.2**	1.7
Prepaid expenses and other assets	1, 12	**32.0**	28.3
		1,327.9	1,335.1
Property, plant and equipment	1, 10	**6,732.7**	6,007.5
Intangibles	1, 11	**241.8**	209.4
Investment in ATCO Structures & Logistics	4	**121.9**	-
Regulatory assets	1, 2	**383.9**	65.3
Derivative assets	24	**31.4**	60.4
Other assets	1, 12	**244.0**	182.3
		$9,083.6	$7,860.0
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	13	**$ -**	$ 22.0
Accounts payable and accrued liabilities		**382.1**	479.5
Income taxes payable	3, 7	**-**	4.9
Regulatory liabilities	1, 2	**26.1**	29.3
Derivative liabilities	24	**2.9**	5.4
Long term debt due within one year	14	**2.8**	17.7
Non-recourse long term debt due within one year	14	**49.0**	44.8
		462.9	603.6
Future income taxes	1, 7	**478.1**	163.3
Regulatory liabilities	1, 2	**571.2**	148.6
Derivative liabilities	24	**5.9**	12.4
Deferred credits	15	**277.3**	301.9
Long term debt	14	**3,102.3**	2,844.3
Non-recourse long term debt	14	**354.8**	412.4
Equity preferred shares	16	**785.0**	625.0
Class A and Class B share owners' equity			
Class A and Class B shares	17	**528.3**	521.9
Contributed surplus	19	**3.2**	2.6
Retained earnings		**2,568.6**	2,279.1
Accumulated other comprehensive income	25	**(54.0)**	(55.1)
Retained earnings and accumulated other comprehensive income		**2,514.6**	2,224.0
		3,046.1	2,748.5
		$9,083.6	$7,860.0

DIRECTOR

DIRECTOR

Canadian Utilities Limited
Consolidated Statement of Cash Flows

(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2009	2008	Year Ended December 31 2009	2008
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 127.1**	$ 114.5	**$ 466.6**	$ 414.5
Adjustments for:					
Depreciation and amortization	1	**80.4**	100.1	**329.7**	387.2
Future income taxes	1	**(5.3)**	(8.7)	**0.8**	(3.8)
Gain on ATCO Structures & Logistics transaction	4	**-**	-	**(33.9)**	-
Earnings from investment in ATCO Structures & Logistics less dividends received	4	**1.0**	-	**(1.9)**	-
TXU Europe settlement - net of income taxes	5	**(2.1)**	(2.4)	**(8.9)**	(9.8)
Mark to market of natural gas purchase and power generation revenue contracts	6	**2.7**	1.6	**9.9**	2.8
Other post employment benefit adjustment		**-**	(2.1)	**-**	(9.4)
Deferred availability incentives		**3.7**	16.1	**5.9**	19.5
Changes in non-current regulatory assets and liabilities	1	**31.4**	25.5	**41.6**	(7.2)
Allowance for equity funds used during construction		**(3.5)**	(2.6)	**(9.0)**	(6.9)
Other		**(6.3)**	7.1	**(7.4)**	9.6
		229.1	249.1	**793.4**	796.5
Changes in non-cash working capital	20	**(65.9)**	(79.2)	**(55.1)**	(12.8)
Cash flow from operations	1	**163.2**	169.9	**738.3**	783.7
Investing activities					
Purchase of property, plant and equipment	1, 12	**(243.8)**	(355.4)	**(887.5)**	(959.2)
Proceeds on disposal of property, plant and equipment		**-**	(2.7)	**0.2**	(2.0)
Contributions by utility customers for extensions to plant		**20.7**	38.4	**114.1**	176.3
Purchase of intangibles	1	**(29.9)**	(20.9)	**(58.6)**	(51.7)
Changes in non-cash working capital	20	**52.8**	25.3	**(29.5)**	37.4
Other		**4.0**	(2.1)	**9.2**	(6.9)
	1	**(196.2)**	(317.4)	**(852.1)**	(806.1)
Financing activities					
Issue of long term debt	14	**23.7**	4.0	**399.7**	370.7
Repayment of long term debt	14	**(125.3)**	(3.8)	**(134.1)**	(112.0)
Repayment of non-recourse long term debt	14	**(12.2)**	(28.6)	**(55.8)**	(85.2)
Issue of equity preferred shares by subsidiary	16	**-**	-	**160.0**	-
Net issue of Class A shares		**3.7**	0.1	**6.4**	5.0
Dividends paid to Class A and Class B share owners		**(44.3)**	(41.7)	**(177.1)**	(166.8)
Changes in non-cash working capital	20	**-**	(0.2)	**-**	(0.1)
Other		**1.0**	1.4	**(2.1)**	1.5
	1	**(153.4)**	(68.8)	**197.0**	13.1
Foreign currency translation		**(1.4)**	(3.2)	**(4.9)**	(11.3)
Cash position [(1)]					
Increase (decrease)		**(187.8)**	(219.5)	**78.3**	(20.6)
Decrease in cash on ATCO Structures & Logistics transaction	4	**-**	-	**(8.9)**	-
Beginning of period		**983.8**	946.1	**726.6**	747.2
End of period		**$ 796.0**	$ 726.6	**$ 796.0**	$ 726.6

(1) Cash position consists of cash and short term investments less bank indebtedness

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income

(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2009	Three Months Ended December 31 2008	Year Ended December 31 2009	Year Ended December 31 2008
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$127.1**	$114.5	**$466.6**	$414.5
Other comprehensive income, net of income taxes:					
Cash flow hedges	25	**1.3**	(4.2)	**8.3**	(6.9)
Foreign currency translation adjustment	25	**(3.1)**	(5.4)	**(6.1)**	(15.1)
		(1.8)	(9.6)	**2.2**	(22.0)
Comprehensive income		**$125.3**	$104.9	**$468.8**	$392.5

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation and Consolidation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments and an equity accounted for investment in ATCO Structures & Logistics (the "Corporation"). Significant investments and principal subsidiaries are listed below. Subsidiaries are wholly-owned, unless otherwise indicated.

Significant Investments and Principal Operating Subsidiaries	Principal activity
ATCO Structures & Logistics (1)	Infrastructure solutions including support services & logistics, modular building solutions and supply, and construction of noise management solutions
ATCO Power	Power generation
ATCO Midstream	Natural gas gathering, processing, storage and natural gas liquids extraction
ATCO I-Tek	Information systems and technologies
CU Inc.	Holding company
ATCO Gas (2)	Natural gas distribution
ATCO Pipelines (2)	Natural gas transmission
ATCO Electric (2)	Electric transmission and distribution
Alberta Power (2000) (2)	Power generation

(1) At December 31, 2009, the Corporation has an ownership interest of 24.5% and ATCO Ltd. (the parent company of the Corporation) has an ownership interest of 75.5%. The Corporation accounts for its investment in ATCO Structures & Logistics under the equity method.
(2) Wholly owned by CU Inc.

Significant joint venture investments consist principally of power generation plants; a substantial portion of ATCO Power's operations are conducted through joint ventures.

Accounting Changes

Accounting for Rate Regulated Operations

Effective January 1, 2009, the Canadian Institute of Chartered Accountants ("CICA") removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. Previously, the Corporation followed Canadian GAAP recommendations, which were similar to standards issued by the Financial Accounting Standards Board ("FASB") in the United States, which provide guidance on the recognition and measurement of assets and liabilities arising from rate regulation. As permitted by Canadian GAAP, the Corporation has applied standards issued by FASB as

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

another source of Canadian GAAP. This change in accounting policy has been adopted prospectively with changes identified below. Although the standards are similar, key differences are outlined below.

The reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the Corporation's total assets and total liabilities. The Corporation reclassified $376.2 million at January 1, 2009, corresponding to these reserves.

Previously, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs for the utility operations. An amount corresponding to this provision is incorporated into rates charged to customers and was previously recognized in revenues. Under the new method of accounting, the Corporation does not recognize this amount in depreciation and amortization expense and revenues. The Corporation now recognizes operation and maintenance expense and revenues as actual removal and site restoration costs are incurred. As a result of the change in accounting, for the unaudited three months ended December 31, 2009, depreciation and amortization expense was $13.8 million lower, revenues were $5.9 million lower, and operations and maintenance expense was $7.9 million higher, resulting in no change in earnings. For the year ended December 31, 2009, depreciation and amortization expense was $54.0 million lower, revenues were $36.4 million lower, and operations and maintenance expense was $17.6 million higher, resulting in no change in earnings.

Effective January 1, 2009, the Corporation also adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of $255.6 million at January 1, 2009.

Concurrent with the changes in accounting for rate regulated operations noted above, the Corporation changed its presentation of changes in regulatory accounts within the statement of cash flows. Certain items relating to changes in rate regulated assets and liabilities that were previously included in investing and financing activities are now reported in operating activities. The inclusion of changes in the non-current regulatory assets and liabilities in operating activities provides more relevant information on the activities of the Corporation. Comparative figures have been restated as follows:

	Three Months Ended December 31, 2008			Year Ended December 31, 2008		
	Amount Previously Reported	Amount Reclassified	Amount Restated	Amount Previously Reported	Amount Reclassified	Amount Restated
		(Unaudited)				
Cash flow from operations	$ 145.3	$ 24.6	$ 169.9	$ 791.8	$(8.1)	$ 783.7
Investing activities	(290.3)	(27.1)	(317.4)	(813.1)	7.0	(806.1)
Financing activities	(71.3)	2.5	(68.8)	12.0	1.1	13.1

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible Assets

Effective January 1, 2009, the Corporation adopted the CICA recommendations for goodwill and intangible assets which established standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets).

This change in accounting has been adopted retrospectively and had the following effect on the consolidated financial statements for the years ended December 31, 2009 and December 31, 2008:

(a) Restatement of opening retained earnings at January 1, 2008, to recognize the prior years' earnings effect of amounts capitalized prior to 2008 that do not meet the definition of intangible assets as now defined by GAAP (see Note 8).
(b) Restatement of depreciation and amortization expense and future income taxes for 2008 for the effect of amounts capitalized and amortized in 2008 and prior periods that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
(c) Restatement of opening accumulated other comprehensive income at January 1, 2008, for the effect of amounts capitalized prior to 2008 that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
(d) Reclassification of $209.4 million included in property, plant and equipment and other assets to intangible assets on the balance sheet at December 31, 2008.
(e) Restatement of operating activities in the statement of cash flows for the impact of changes resulting from (b) above and a reclassification within investing activities of $51.7 million from purchases of property, plant and equipment to purchases of intangibles for 2008.

Certain comparative figures, in addition to those identified above, have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2. The Corporation records revenues and/or other adjustments arising from an interim or final rate decision related to current and/or prior years upon receipt of the decision.

Significant Judgments and Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make judgments, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to revenue recognition, regulatory assets and liabilities, depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, pensions and other post-employment benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

differ from those estimates. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Revenue Recognition

Regulated Operations:

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas and ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of the respective commodity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period.

Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Measurement of the estimate of usage not yet billed is based on historical consumption patterns. Management applies judgment to the measurement of the estimated consumption and to the valuation of that consumption.

Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Non-regulated Operations:

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues resulting from the supply of contracted products and services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided. Billings in excess of earned revenue are deferred as unearned revenue.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Natural Gas Supply

Natural gas supply expense for ATCO Midstream, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense for regulated operations of ATCO Electric in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Franchise Fees

Franchise fees are charged to ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") by municipal governments for the exclusive right to provide service in their community. These costs are charged to the related customers through rates that must first be approved by the Alberta Utilities Commission ("AUC"). Franchise fee revenues and expenses are therefore recognized separately and are not recorded on a net basis.

Income Taxes

The Corporation follows the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. For the regulated operations, effective January 1, 2009, a separate regulatory asset or liability is recognized for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. Previously the regulated operations' future income tax assets or liabilities were not recognized unless future income taxes were provided in the income tax component of current rates.

Cash and Short Term Investments

Short term investments consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AUC for debt and equity capital. Property, plant and equipment in the non-regulated subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AUC. On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Intangibles

Intangibles mainly include computer software not directly attributable to the operation of property, plant and equipment and land rights and are recorded at cost less accumulated amortization and unamortized contributions by utility customers. The assets are amortized on a straight- line basis over their useful lives; which are not longer than 10 years for computer software and between 75 and 100 years for land rights.

Impairment

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue in accordance with regulatory practice and issue costs of preferred shares relating to non-regulated subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's presentation of long term debt and non-recourse long term debt are reduced by the respective deferred financing charges.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Leases

The Corporation is party to certain arrangements that convey the right to use non-regulated electric transmission assets and are classified as leases with the Corporation as the lessor. Leases are classified as finance leases when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as receivables included within other assets. Finance lease receivables are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Finance lease income is recognized in a manner that produces a constant rate of return on the Corporation's investment in the lease and is included in interest and other income.

Deferred Availability Incentives

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using discounted future cash flows.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated and non-regulated electricity generating plants and the natural gas liquids extraction and processing plants.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, highly effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

In estimating fair value, the Corporation utilizes quoted market prices when available. Models incorporating observable market data along with transaction specific factors are also utilized in estimating fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels. The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs)

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

CICA recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003 have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

   At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

   A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

   If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

   If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

   Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
   (i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
   (ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit ("OPEB") plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

Monetary assets and liabilities of integrated foreign operations, as well as non-monetary assets carried at market value, are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date. Other non-monetary assets and non-monetary liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred. Revenues and expenses are translated at the average monthly rates of exchange during the year; depreciation and amortization are translated at rates of exchange consistent with the assets to which they relate. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions that are denominated in foreign currencies are translated at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at market value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, accounting, and service area.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AUC. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPA's expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. Further details with respect to return on equity, capitalization and the generic cost of capital decisions from the AUC are included in Note 3.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. As described in Note 1, effective January 1, 2009, certain of the treatments under accounting for rate regulated operations have been changed by the Corporation. These changes in accounting treatment are noted below in the respective descriptions of the regulatory assets and liabilities.

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AUC renders a decision concerning these adjustments.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The regulatory assets and liabilities comprise the following:

	2009	2008
Regulatory assets – current:		
Deferred electricity cost recoveries[1]	**$ 16.1**	$ 26.1
Deferral of unused vacation costs[2]	**14.5**	14.7
Deferred load balancing transactions[3]	**5.0**	2.9
Current income tax savings associated with future income tax refund to customers[4]	**1.8**	1.9
Other regulatory assets[12]	**-**	10.2
	$ 37.4	$ 55.8
Regulatory assets – non-current:		
Future income tax recoveries[5]	**$299.2**	$ -
Regulatory other post employment benefits asset (Note 23)[6]	**51.3**	46.9
Deferred load balancing transactions[3]	**14.4**	-
Deferred hearing costs[7]	**9.9**	8.4
Current income tax savings associated with future income tax refund to customers[4]	**3.2**	5.2
Reserves for injuries and damages[8]	**1.5**	-
Other regulatory assets[12]	**4.4**	4.8
	$383.9	$ 65.3
Regulatory liabilities – current:		
Deferred load balancing transactions[3]	**$ 18.1**	$ 20.9
Deferred electricity costs[1]	**-**	5.6
Other regulatory liabilities[12]	**8.0**	2.8
	$ 26.1	$ 29.3
Regulatory liabilities – non-current:		
Reserves for future removal and site restoration[9]	**$402.4**	$ -
Regulatory pension liability (Note 23)[6]	**120.9**	110.2
Deferred royalty credits[10]	**16.8**	23.3
Deferral of temperature impact on revenues[11]	**10.5**	2.7
Deferred electricity costs[1]	**6.1**	-
Reserves for injuries and damages[8]	**1.0**	3.3
Other regulatory liabilities[12]	**13.5**	9.1
	$571.2	$148.6

[1] Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Electric System Operator ("AESO"). The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC and not adjusted.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

In Alberta, major transmission capital projects are planned by the AESO and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AUC is obtained for refund to or collection from the AESO, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC and not adjusted.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on customer rates approved by the AUC and not adjusted.

Consequently, revenues in 2009 would have been $10.5 million higher (2008 – $8.6 million lower) in the absence of rate regulation.

(2) Deferral of unused vacation costs

Revenue requirement includes a recovery from customers for vacation entitlement taken by employees during the year. A portion of the vacation entitlement is earned by employees and accrued as a liability in the prior year. GAAP requires that in the absence of rate regulation the vacation pay liability be expensed in the year accrued and not deferred for amounts that will be recovered from customers. Consequently, expenses for 2009 would have been $0.2 million lower (2008 - $0.8 million higher) in the absence of rate regulation.

(3) Deferred load balancing transactions

ATCO Gas and ATCO Pipelines have received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Gas' and ATCO Pipelines' North and South distribution and transmission pipeline systems.

Should the deferral account for either ATCO Gas' North or South systems exceed $2.0 million over three successive months, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. As a result of an AUC decision received on December 14, 2009, the requirements to submit an application were prospectively changed to amounts exceeding $5.0 million over six successive months or $10.0 million for one month.

Should the deferral account for either ATCO Pipelines' North or South systems exceed $2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. On January 29, 2009, a decision was received that increased these amounts to $7.5 million for the North and $5.0 million for the South.

GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2009 would have been $23.3 million higher and revenues in 2009 would have been $4.3 million higher (2008 – $26.6 million higher revenues) in the absence of rate regulation.

[4] Current income tax savings associated with future income tax refund to customers

The AUC directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

GAAP requires that in the absence of rate regulation revenues not be adjusted for the current income tax savings to be realized in future periods. Consequently, revenues for 2009 would have been $2.2 million higher (2008 - $2.0 million higher) in the absence of rate regulation.

[5] Future income tax recoveries

As described in Note 1, the Corporation prospectively adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of $255.6 million at January 1, 2009. GAAP requires that in the absence of rate regulation future income taxes be expensed in the period in which they are incurred and not deferred for amounts that will be recovered from or paid to customers. Consequently, expenses in 2009 would have been $43.6 million higher in the absence of rate regulation.

[6] Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AUC decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan

cost in 2009 would have been $10.4 million lower (2008 – $0.9 million lower), and other post employment benefit plan cost in 2009 would have been $2.4 million higher (2008 – $2.4 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2009 would have been $0.8 million lower (2008 – $1.2 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2009, the utilities amortized $3.9 million (2008 – $3.4 million) of the deferred pension asset.

(7) Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervener groups that have been reimbursed by the utilities as directed by the AUC. Prior to 2009, hearing costs were deferred to the balance sheet and amortized using AUC approved annual amounts that are collected through customer rates. Effective January 1, 2009, hearing costs are expensed as actual costs are incurred and revenues are adjusted for variances between the approved annual amounts and actual costs. The variances continue to be deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between approved annual amounts and actual costs and that hearing costs be expensed in the period in which they are incurred. Consequently, revenues in 2009 would have been $1.5 million lower (2008 - $4.4 million higher expenses) in the absence of rate regulation.

(8) Reserves for injuries and damages

The AUC has approved the use of a reserve for injuries and damages by the utilities as a means of self-insurance. The reserve for injuries and damages is established based on an annual amount approved by the AUC to be collected through customer rates. Prior to 2009, reserve claims were deferred to the balance sheet and amortized using AUC approved annual amounts that are collected through customer rates. Effective January 1, 2009, reserve claims are now expensed as actual costs are incurred and revenues are adjusted for variances between the approved annual amounts and actual costs. The variances continue to be deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between approved annual amounts and actual costs and that claims be expensed in the period in which they are incurred. Consequently, revenues in 2009 would have been $3.8 million lower (2008 - $1.6 million higher expenses) in the absence of rate regulation.

(9) Reserves for future removal and site restoration

As described in Note 1, the reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the utilities' total assets and total liabilities. The utilities

reclassified $376.2 million at January 1, 2009, corresponding to these reserves. Prior to 2009, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs. An amount corresponding to this provision is incorporated into rates charged to customers. Effective January 1, 2009, actual removal and site restoration costs are expensed as incurred and revenues are adjusted for variances between the provision incorporated into rates and actual costs. The variances continue to be deferred as reserves for future removal and site restoration costs. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between the provision incorporated into rates and actual costs. Consequently, revenues in 2009 would have been $26.2 million higher in the absence of rate regulation.

(10) Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs are expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that in the absence of rate regulation royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2009 would have been $6.5 million higher (2008 - $0.2 million lower) in the absence of rate regulation.

(11) Deferral of temperature impact on revenues

ATCO Gas has received AUC approval to establish deferral accounts to mitigate the impact of temperature fluctuations on its revenues. Should the deferral account for either the North or the South exceed $7.0 million at April 30th of any year, ATCO Gas will submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. Costs related to financing these deferred amounts will be charged monthly to these deferral accounts based on ATCO Gas' weighted average cost of capital. GAAP requires that in the absence of rate regulation the temperature impacted revenues be recognized in the period in which they are realized. Consequently, revenues in 2009 would have been $11.8 million higher (2008 – $2.7 million higher) in the absence of rate regulation.

(12) Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines received AUC approval on February 27, 2009 to recover or refund these deferral account balances in its general rate application negotiated settlement. GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2009 would have been $2.9 million higher (2008 – $0.6 million higher) and expenses would have been $2.4 million lower (2008 – $0.4 million lower) in the absence of rate regulation. Assets of nil and nil (2008 – $0.3 million and $1.9 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of $3.3 million and $1.2 million (2008 – $1.4 million and $0.1 million) are included in current and non-current regulatory liabilities respectively.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

b) In November 2009, the AUC directed ATCO Gas to establish a deferral account to capture variances between forecast and actual costs that may be capitalized for accounting purposes but deducted in the year incurred as an expense for income tax purposes. The resulting impact of this decision was to decrease ATCO Gas' 2009 revenues by $3.6 million. Consequently, revenues in 2009 would have been $3.6 million higher (2008 – nil) in the absence of rate regulation. Liabilities of $4.3 million (2008 – nil) are included in non-current regulatory liabilities.

c) ATCO Pipelines has received AUC approval to establish a deferral account for the Salt Cavern Storage facility to collect the gains or losses and transaction costs associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AUC, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed $2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. ATCO Pipelines received AUC approval to recover this deferral account balance in its general rate application negotiated settlement on March 18, 2009. GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2009 would have been $6.3 million lower (2008 – revenues $1.9 million lower) in the absence of rate regulation. Assets of $1.5 million are included in non-current regulatory assets (2008 - $7.8 million included in current regulatory assets) in the balance sheet.

Other items affected by rate regulation

The AUC permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

3. REGULATORY MATTERS

Generic Cost of Capital Decision

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity ("ROE") at 9.0% for all Alberta utilities which it regulates. This is an increase over the 8.61% ROE that the adjustment formula formerly in place would have provided for 2009. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric's transmission operations, 39% for both ATCO Electric's distribution operations and ATCO Gas' operations and 45% for ATCO Pipelines' operations. As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. The financial impact of this decision was an increase to ATCO Electric's earnings of $4.2 million and ATCO Gas' earnings of $2.5 million, of which $0.4 million relates to 2008. The changes did not apply to ATCO Pipelines for 2009 since capital structure and rate of return were included in ATCO Pipelines' Negotiated Settlement.

3. **REGULATORY MATTERS** (continued)

While ATCO Gas' ROE for 2008 was not impacted by the decision issued on November 12, 2009, a separate module within the generic proceeding addressed ATCO Gas' 2008 capital structure, as inclusion of this issue was removed from its 2008/2009 general rate application. The November 12, 2009 decision approved an equity ratio of 39% commencing in the year 2008 for ATCO Gas. The financial impact is identified in the 2008 amount noted above.

Benchmarking

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received on January 23, 2008 and filed with the AUC in February 2008, along with an application to adjust placeholders for 2003 – 2007 for ATCO Gas, ATCO Electric and ATCO Pipelines. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010. A subsequent process to adjust 2008 and 2009 placeholders as well as a separate process to deal with services provided by ATCO I-Tek for 2010 and beyond are expected to occur in 2010.

Income Tax Module

On November 12, 2009, the AUC issued its Income Tax Module decision in which it addressed the 2008-2009 income tax placeholder amounts for ATCO Gas and 2009-2010 placeholders for ATCO Electric. The AUC approved the placeholder amounts as filed and established an income tax deferral account for ATCO Electric and ATCO Gas, resulting in no impact to earnings for ATCO Electric and a $2.5 million reduction in earnings for ATCO Gas.

Company Specific Decisions

ATCO Electric

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. On March 11, 2009, ATCO Electric filed an application requesting an increase to its approved interim refundable rates for its distribution operations. A decision from the AUC was received on April 22, 2009, which resulted in an increase to the interim refundable rates to 67% of the requested rate increase.

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application. The effect of the decision increased ATCO Electric's 2009 annual earnings primarily as a result of an increase in rate base. In the decision, the AUC used placeholders for 2009 and 2010 information technology and customer care and billing rates and pension costs. These placeholders will be determined by the AUC in subsequent proceedings. The placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The placeholders in the decision for the income amounts were determined as a result of the Income Tax Module Decision discussed above.

3. **REGULATORY MATTERS** (continued)

ATCO Gas

On November 13, 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009. The effect of the decision increased ATCO Gas' 2009 annual earnings primarily from an increase in rate base. In the decision, the AUC used placeholders for 2009 information and technology and customer care and billing costs. These placeholders will be determined by the AUC in subsequent proceedings. The placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The placeholders for income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

As a result of numerous regulatory and legal proceedings, ATCO Gas received approval from the AUC to remove its Carbon storage facility from regulation and, effective July 1, 2008, to suspend rate riders to customer rates (Carbon Rate Riders) on an interim basis. ATCO Gas derecognized regulatory assets and liabilities relating to the Carbon Facility as these amounts were no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by $1.9 million. Further to its decision suspending Carbon Rate Riders, the AUC on July 28, 2009, issued a decision approving a refund to customers related to the costs of the Carbon facility that were included in ATCO Gas' rates from January through June 2008. Consequently, ATCO Gas recognized increased revenues of $13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008 to June 30, 2008 which was previously refunded to customers and decreased revenues of $7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net impact was an increase to ATCO Gas' revenues and earnings of $6.2 million and $4.5 million, respectively, in 2009.

For the remaining period of April 1, 2005 to December 31, 2007, ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of $20.5 million, excluding interest. On December 16, 2009, a Review and Variance Decision issued by the AUC approved the effective date of removing the Carbon facility from regulation to be April 1, 2005. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas. The City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could affect the amount ATCO Gas is seeking to recover from customers. A hearing for the Leave to Appeal application has been tentatively scheduled for April 28, 2010.

ATCO Pipelines

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers for ATCO Pipelines' 2008 and 2009 revenue requirements. On March 18, 2009, the AUC issued a decision approving the negotiated settlement, including, among other things, a rate of ROE of 8.75% and a common equity ratio of 43% for each of 2008 and 2009. As a result of the decision, ATCO Pipelines recognized additional earnings over existing interim rates of $4.5 million in the first quarter of 2009, of which $3.7 million related to 2008.

3. REGULATORY MATTERS (continued)

On June 26, 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA Gas Transmission Ltd.'s gas transmission systems in Alberta (Integration Application). A settlement on ATCO Pipelines 2010, 2011 and 2012 revenue requirements was successfully negotiated with interested parties on October 28, 2009. On November 12, 2009, ATCO Pipelines filed a request with the AUC to approve this negotiated settlement as part of its Integration Application. ATCO Pipelines expects to receive an AUC decision on the Integration Application in the first half of 2010.

Other

The Corporation has a number of other less significant regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent ATCO Ltd. finalized a transaction combining ATCO Frontec, a wholly-owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO Ltd ("ATCO Structures & Logistics Transaction"). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

This is a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation; with an after tax gain for accounting purposes of $29.6 million recorded on closing. Prior to the ATCO Structures & Logistics Transaction, the Corporation consolidated ATCO Frontec as it was a wholly-owned subsidiary. Therefore, all revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation for the period up to June 30, 2009. From July 1, 2009, the Corporation has recorded an equity accounted for investment for its 24.5% interest in ATCO Structures & Logistics as it retains significant influence. This is reflected as a single line item called "Earnings from investment in ATCO Structures & Logistics" on the consolidated statement of earnings and a single line item called "Investment in ATCO Structures & Logistics" on the consolidated balance sheet. The Investment in ATCO Structures & Logistics is increased or decreased to include the Corporation's share of earnings and capital transactions from July 1, 2009 onward.

The transaction allows the predecessor companies (ATCO Frontec, ATCO Structures, and ATCO Noise Management) to pursue a more efficient working relationship in response to a changing global market and the demand for bundled services.

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT (continued)

The Corporation's investment in ATCO Structures & Logistics at December 31, 2009 is as follows:

Investment at July 1, 2009	**$121.8**
Share of earnings	**7.8**
Share of other comprehensive income	**(1.8)**
Dividends received	**(5.9)**
Investment at December 31, 2009	**$121.9**

5. TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Corporation's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Corporation's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2009, earnings after income taxes of approximately $6.4 million have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

6. INTEREST AND OTHER INCOME

	2009	2008
Interest	**$22.6**	$43.6
Allowance for funds used during construction by regulated operations	**23.4**	17.9
(Losses) gains on dispositions of property, plant and equipment and other investments	**(0.3)**	2.3
Loss on natural gas purchase contracts derivative asset (Note 24)	**(34.1)**	(12.4)
Gain on power generation revenue contract liability (Note 24)	**24.2**	9.6
Cash flow hedge gains (losses)	**2.1**	(4.8)
Finance lease income	**3.4**	-
Other	**2.0**	2.9
	$43.3	$59.1

7. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2009		2008	
Earnings before income taxes	**$632.7**	%	$581.8	%
Income taxes, at statutory rates	**$183.5**	**29.0**	$171.6	29.5
H.R. Milner income tax reassessment	**(7.8)**	**(1.2)**	-	-
Removal of Carbon storage assets from regulation	**5.8**	**0.9**	-	-
Benefit of purchased tax losses in UK	**(2.4)**	**(0.4)**	-	-
Part VI.1 tax	**2.5**	**0.4**	1.6	0.3
Future income taxes relating to regulated operations	**(36.7)**	**(5.8)**	(27.2)	(4.7)
Future income taxes recorded at less than current statutory rates	**(1.1)**	**(0.1)**	(1.6)	(0.3)
Non-taxable portion of gain on ATCO Structures & Logistics transaction	**(4.3)**	**(0.7)**	-	-
Earnings from investment in ATCO Structures & Logistics	**(2.3)**	**(0.4)**	-	-
Foreign tax rate variance	**(0.7)**	**(0.1)**	(1.5)	(0.3)
Non-deductible interest on foreign financing	**1.6**	**0.2**	1.4	0.2
Other tax reassessments	**(2.7)**	**(0.4)**	(9.7)	(1.7)
Other	**(10.0)**	**(1.6)**	0.2	0.1
	125.4	**19.8**	134.8	23.1
Current income taxes	**114.7**		129.8	
Future income taxes	**$ 10.7**		$ 5.0	

The future income tax liabilities (assets) comprise the following:

	2009	2008
Property, plant and equipment	**$501.3**	$212.1
Intangibles	**51.8**	1.9
Deferred assets and liabilities	**(71.2)**	(40.2)
Tax loss carryforwards	**(17.4)**	(19.0)
Derivative financial instruments	**1.1**	0.3
Other	**5.9**	2.3
	471.5	157.4
Less: Current future income tax asset	**(6.6)**	(5.9)
	$478.1	$163.3

7. INCOME TAXES (continued)

As described in Note 1, effective January 1, 2009, the Corporation adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. As a result of adopting these recommendations, the Corporation recorded previously unbooked future income tax liabilities of the regulated operations.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering Canada Revenue Agency ("CRA") to reverse its 2006 reassessment of Alberta Power (2000)'s 2001 tax return for the sale of the H.R. Milner generating plant. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA.

The impact of the judgment is a $7.8 million recovery of income tax and $5.9 million of related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) will receive interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments have resulted in a $16.8 million increase in earnings for 2009. CRA will be required to refund Alberta Power (2000) approximately $28.0 million including interest and net of consequential adjustments to other taxation years arising from the judgment. Of this amount, the CRA has refunded $20.8 million as of December 31, 2009, and approximately $7.2 million remains outstanding from the Government of Alberta.

In 2009, ATCO Gas removed the Carbon storage assets from regulation (see Note 3). As a result, the Corporation recorded future income taxes of $5.8 million.

ATCO Power has tax loss carryforwards of $70.2 million for which it has recorded an income tax benefit. The losses are the result of refiling corporate income tax returns to maximize previous years unclaimed capital cost allowance. Approximately 27% of the losses expire in 2010, with the remaining amounts expiring in 2014 and 2015.

Income taxes paid amounted to $122.2 million (2008 — $125.4 million).

8. RETAINED EARNINGS AT BEGINNING OF PERIOD AS RESTATED

	January 1	
	2009	2008
Retained earnings at beginning of period as previously reported	**$2,282.3**	$2,036.0
Cumulative adjustments to retained earnings to recognize the prior years' effect of the change in the method of accounting for intangible assets (net of income taxes)	**(3.2)**	(4.6)
Retained earnings at beginning of period as restated	**$2,279.1**	$2,031.4

9. INVENTORIES

	2009	2008
Natural gas and fuel in storage	**$23.5**	$ 45.9
Raw materials and consumables	**56.0**	63.0
Finished goods	**0.3**	0.4
	$79.8	$109.3

For the year ended December 31, 2009, the amount of inventories recognized as an expense was $73.6 million (2008 – $98.9 million). There have been $0.2 million write-downs to net realizable value and there have been no reversals of previous write-downs to net realizable value.

No inventories are pledged as security for liabilities.

10. PROPERTY, PLANT AND EQUIPMENT

		2009		2008	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	2.8%	**$ 8,157.4**	**$2,396.7**	$ 7,475.7	$2,612.4
Energy	3.8%	**3,194.0**	**1,372.8**	3,102.9	1,270.1
Corporate & Other[(1)]	9.2%	**88.6**	**50.4**	199.0	87.0
		$11,440.0	**3,819.9**	$10,777.6	3,969.5
Property, plant and equipment less accumulated depreciation			**7,620.1**		6,808.1
Unamortized contributions by utility customers for extensions to plant			**887.4**		800.6
			$6,732.7		$6,007.5

[(1)] *2008 includes amounts for ATCO Frontec*

Accumulated depreciation no longer includes amounts provided for future removal and site restoration costs, net of salvage value (2008 — included $376.2 million). As described in Note 1, at January 1, 2009, the Corporation reclassified $376.2 million relating to the utility operations from accumulated depreciation to non-current regulatory liabilities.

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $376.8 million (2008 — $412.0 million) and non-depreciable assets of $55.3 million (2008 — $45.7 million).

11. INTANGIBLES

	December 31			
	2009		2008	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Computer Software	**$314.3**	**$170.3**	$275.1	$151.9
Land Rights	**115.0**	**22.1**	101.3	20.6
Other	**11.4**	**6.2**	11.3	5.4
	$440.7	**198.6**	$387.7	177.9
Intangibles less accumulated amortization		**242.1**		209.8
Unamortized contributions by utility customers		**0.3**		0.4
		$241.8		$209.4

Amortization expense relating to intangibles was $23.5 million (2008 – $22.9 million).

12. OTHER ASSETS

	2009	2008
Accrued pension asset (Note 23)	**$141.6**	$133.4
Security deposits for debt	**17.0**	17.8
Lease receivable[(1)]	**57.8**	-
Long term receivable from joint venture	**-**	7.3
Other	**27.6**	23.8
	$244.0	$182.3

[(1)] *In June 2009, the Corporation finalized agreements relating to the use of certain non-regulated electric transmission assets that are accounted for as finance leases (with the Corporation as the lessor). As at December 31, 2009, the total net investment in finance leases is $59.1 million. The current portion which totals $1.3 million is included in prepaid expenses and other assets and the long-term portion of $57.8 million is included in other assets above.*

13. BANK INDEBTEDNESS AND LINES OF CREDIT

At December 31, 2009, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

		2009			2008	
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$48.0**	**$278.0**	$ 326.0	$ 48.2	$277.8
Short term committed	**600.0**	**32.0**	**568.0**	600.0	54.1	545.9
Uncommitted	**63.7**	**7.0**	**56.7**	99.1	28.1	71.0
	$989.7	**$87.0**	**$902.7**	$1,025.1	$130.4	$894.7

13. BANK INDEBTEDNESS AND LINES OF CREDIT (continued)

Of the $87.0 million used (2008 – $130.4 million) at December 31, 2009, $47.0 million (2008 – $47.0 million) is included in long term debt, nil (2008 – $22.0 million) is included in bank indebtedness and $40.0 million (2008 – $61.4 million) represents outstanding letters of credit.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	Effective Interest Rate	**2009**	2008
Canadian Utilities			
CU Inc. debentures – unsecured			
1989 Series 10.20% due November 2009	10.331%	**$ -**	$ 125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	35.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2009 6.215% due March 2024	6.278%	**120.0**	-
2008 5.563% due May 2028	5.614%	**125.0**	125.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	220.0
2008 5.580% due May 2038	5.622%	**200.0**	200.0
2009 6.500% due March 2039	6.550%	**150.0**	-
CU Inc. other long term obligation, due June 2011, unsecured	2.250%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(15.3)**	(15.0)
		2,924.2	2,779.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2013, unsecured [1]	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2013, secured by a pledge of cash [1]	Floating	**22.0**	22.0
ATCO Power Australia credit facility, at BBSY rates, due June 2015: AUD100.0 million, secured by a pledge of project's assets and contracts	Floating [2]	**94.4**	-

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

***Long term debt** (continued)*

	Effective Interest Rate	2009	2008
ATCO Frontec (see note 4) credit facility, at Euribor rates, due October 2010: 2008 - €20.8 million, secured by a pledge of assets and certain contracts	Floating [2]	-	35.5
Canadian Utilities Limited non-revolving credit facility at 5.72%, due June 2014	5.884%	**39.5**	-
		3,105.1	2,862.0
Less: Amounts due within one year		**2.8**	17.7
		$3,102.3	$2,844.3

Non-recourse long term debt

Project Financing	Effective Interest Rate	2009	2008
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010: (£6.6 million (2008 – £12.5 million))	7.95%	**$ 11.2**	$ 22.2
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 [1]: ($22.1 million AUD (2008 – $26.2 million AUD))	Floating [2]	**20.9**	22.5
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2013 [1]	Floating [2]	**30.1**	49.4
Joffre:			
Term loan, at BA rates, due to 2012 [1]	Floating [2]	**0.2**	0.3
Term facility, at Canadian Prime Advances, due to 2012 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2012 [1]	Floating [2]	**0.5**	0.7
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating [2]	**27.5**	32.3
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.3**	0.3
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**7.0**	8.2
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**23.4**	24.4
Muskeg River:			
Term loan, at BA rates, due to 2014 [1]	Floating [2]	**22.4**	26.0
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**5.6**	6.5
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**23.9**	25.7

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

***Non-recourse long term debt** (continued)*

Project Financing	Effective Interest Rate	2009	2008
Brighton Beach:			
Term loan, at BA rates, due to 2020 [1]	Floating [2]	**17.2**	18.3
Term loan, at LIBOR, due to 2020 [1]	Floating [2]	**15.5**	16.4
Construction overrun facility, at BA rates, due to 2020 [1]	Floating [2]	**4.2**	4.5
Construction overrun facility, at LIBOR, due to 2020 [1]	Floating [2]	**3.8**	4.0
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**98.5**	101.8
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**1.2**	1.8
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**33.0**	34.3
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**29.5**	30.6
Less: Deferred financing charges		**(4.3)**	(5.2)
		403.8	457.2
Less: Amounts due within one year		**49.0**	44.8
		$354.8	$412.4

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate
Euribor – Euro Interbank Offered Rate
BBSY – Bank Bill Swap Bid Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2008 — 1.2%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 24).*

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2009 was $1,095.1 million (2008 — $1,095.8 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2009, no amounts were outstanding under the guarantee.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

b) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2009, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$6.2
Brighton Beach project financing	Nil [2]	Nil
Cory project financing	Nil [1]	Nil
Joffre project financing	Nil [1]	$1.5
Muskeg River project financing	Nil [1]	$5.0
Scotford project financing	Nil [1]	$5.1

(1) *No major maintenance reserve required for this financing.*
(2) *Reserve requirements of $0.1 million met with project cash flows.*

c) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2009, the maximum value of the guarantee is $26.4 million.

d) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2009, no such events have occurred.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power generating plants in accordance with acceptable industry operating standards. The guarantee expires on September 30, 2010.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contractual maturities of debt

The undiscounted contractual maturities of long term debt and non-recourse long term debt are as follows:

	Long Term Debt		Non-Recourse Long Term Debt		Total	
	Principal	Interest[1]	Principal	Interest[1]	Principal	Interest[1]
2010	$ 127.8	$ 200.4	$ 49.0	$ 24.7	$ 176.8	$ 225.1
2011	107.6	182.7	42.8	22.4	150.4	205.1
2012	138.4	178.8	40.5	20.2	178.9	199.0
2013	50.7	170.5	36.9	17.9	87.6	188.4
2014	138.4	168.9	33.2	16.1	171.6	185.0
2015 and thereafter	2,557.5	1,985.7	205.7	70.9	2,763.2	2,056.6
	$3,120.4	$2,887.0	$408.1	$172.2	$3,528.5	$3,059.2

[1] *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2009. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

Of the $176.8 million due in 2010, $125.0 million is to be refinanced with new debt or from existing unused long term credit lines and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2009	2008
Long term debt	**$203.8**	$186.3
Non-recourse long term debt	**31.8**	36.8
Bank indebtedness	**2.5**	7.2
Amortization of deferred financing charges	**3.5**	3.2
	$241.6	$233.5

Interest paid amounted to $233.4 million (2008 — $226.7 million).

15. DEFERRED CREDITS

	2009	2008
Accrued other post employment benefits liability (Note 23)	**$ 64.2**	$ 58.5
Deferred availability incentives	**67.1**	61.3
Asset retirement obligations	**83.2**	77.7
Power generation revenue contract liability (Note 24)	**20.4**	44.6
Liability to customers for refund of future income taxes (Note 2)	**12.1**	19.2
Deferred revenues	**3.8**	12.2
Other	**26.5**	28.4
	$277.3	$301.9

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $16.3 million (2008 – $12.6 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2009	2008
Obligations at beginning of year	**$77.7**	$73.1
Accretion expense	**4.1**	3.6
Obligations incurred	**1.4**	1.0
Obligations at end of year	**$83.2**	$77.7

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $137 million, which will be incurred between 2011 and 2052. The credit-adjusted risk-free discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.6%.

16. EQUITY PREFERRED SHARES

CU Inc. equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	2009 Shares	2009 Amount	2008 Shares	2008 Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	4,600,000	$115.0
6.70% Series 2	$25.00	See below	**6,400,000**	**160.0**	-	-
				$275.0		$115.0

On March 27, 2009, CU Inc., a subsidiary corporation, issued $160.0 million Cumulative Redeemable Preferred Shares Series 2 at a price of $25.00 per share. Holders of the Series 2 preferred shares will be entitled to receive, as and when declared by the Board of Directors of the Corporation, fixed cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate of $1.675 per share to yield 6.70% annually. Thereafter the dividend rate will reset every five years to the then current 5-Year Government of Canada bond yield plus 4.81%.

Fair values

Fair values for the CU Inc. preferred shares determined using quoted market prices for the same or similar issues are $278.3 million (2008 - $67.2 million).

Redemption privileges

The Series 1 preferred shares are redeemable at the option of the Corporation commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

On June 1, 2014, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 2 Preferred Shares in whole or in part at par. Holders may elect to convert any or all of their Series 2 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 3 on June 1, 2014, and on June 1 of every fifth year thereafter. Holders of the Series 3 Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 4.81%. On June 1, 2019, and on June 1 of every fifth year thereafter ("Series 3 Conversion Date"), holders of the Series 3 Preferred Shares may elect to convert any or all of their Series 3 Preferred Shares back into an equal number of Series 2 Preferred Shares. On June 1, 2014, or thereafter, CU Inc. may redeem the Series 3 Preferred Shares in whole or in part at $25.00 on a Series 3 Conversion Date or at $25.50 on any other date.

16. EQUITY PREFERRED SHARES (continued)

Canadian Utilities Limited equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	2009 Shares	2009 Amount	2008 Shares	2008 Amount
Cumulative Redeemable Second Preferred Shares						
5.8% Series W	$25.00	See below	**6,000,000**	**$150.0**	6,000,000	$150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$510.0
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**$785.0**		$625.0

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for the Canadian Utilities Limited preferred shares determined using quoted market prices for the same or similar issues are $512.3 million (2008 — $456.3 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

17. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2007	81,508,986	$378.3	43,785,684	$138.6	125,294,670	$516.9
Stock options exercised	215,450	5.0	-	-	215,450	5.0
Converted: Class B to Class A	1,798,558	5.7	(1,798,558)	(5.7)	-	-
December 31, 2008	**83,522,994**	**$389.0**	**41,987,126**	**$132.9**	**125,510,120**	**$521.9**
Stock options exercised	**349,550**	**6.4**	**-**	**-**	**349,550**	**6.4**
Converted: Class B to Class A	**268,736**	**0.8**	**(268,736)**	**(0.8)**	**-**	**-**
December 31, 2009	**84,141,280**	**$396.2**	**41,718,390**	**$132.1**	**125,859,670**	**$528.3**

From January 1, 2010 to February 16, 2010, no stock options were granted, cancelled, or exercised and 1,556,100 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2009	2008	**2009**	2008
	(Unaudited)			
Weighted average shares outstanding	**125,752,093**	125,507,489	**125,637,206**	125,407,951
Effect of dilutive stock options	**156,676**	338,936	**137,044**	376,466
Weighted average dilutive shares outstanding	**125,908,769**	125,846,425	**125,774,250**	125,784,417

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B

17. CLASS A AND CLASS B SHARES (continued)

common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On May 23, 2008, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 22, 2009. From May 23, 2008, to May 22, 2009, no shares were purchased. The Corporation is applying to the Toronto Stock Exchange to recommence its normal course issuer bid in the first quarter of 2010.

18. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital have been:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC for the utility operations.

The Corporation includes share owners' equity, equity preferred shares, long term debt and non-recourse long term debt in its determination of capitalization. In managing its capital, the Corporation considers both the regulated and non-regulated operations in the consolidated group as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long term debt and non-recourse long term debt.

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decisions issued in 2004 and 2009, established the capital structure for each utility. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006. While it has been one of the Corporation's objectives to capitalize its utility operations consistent with the AUC approved capital structure, at December 31, 2009, the Corporation was not capitalized consistent with the 2009 generic cost of capital decision due to the fact that this decision was not received until November 12, 2009. The Corporation will reconsider whether the capital structure should remain consistent with the 2009 generic cost of capital decision for future periods.

While the Corporation's utility operations have had an objective of being capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. The capital structure for the Corporation is set relative to risk and to meet the financial and operational objectives of the Corporation (while considering the decisions of the regulator).

18. CAPITAL DISCLOSURES (continued)

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy has been to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2008.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

The Corporation's key measures of capital structure are as follows:

	2009	2008
Class A and Class B shares	**$ 528.3**	$ 521.9
Contributed surplus	**3.2**	2.6
Retained earnings	**2,568.6**	2,279.1
Accumulated other comprehensive income	**(54.0)**	(55.1)
Equity preferred shares	**785.0**	625.0
Total equity	**3,831.1**	3,373.5
Long term debt	**3,102.3**	2,844.3
Non-recourse long term debt	**354.8**	412.4
Total debt	**3,457.1**	3,256.7
Total capitalization	**$7,288.2**	$6,630.2
Equity capitalization	**53%**	51%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings and higher equity preferred shares due to the preferred share financing for utility capital expenditures. Total debt increased primarily due to financings for utility capital expenditures, ATCO Energy Solutions' business activities and project expenditures and ATCO Power's Karratha project, partially offset by redemptions of long term debt and non-recourse long term debt.

18. CAPITAL DISCLOSURES (continued)

	2009	2008
Interest coverage	**3.5**	3.5
Interest and preferred dividend coverage	**2.8**	2.9

For the year ended December 31, 2009, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants and credit facilities). The Corporation will continue to assess its capital structure and objectives in light of decisions received from the AUC.

19. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,989,500 Class A non-voting shares are available for issuance at December 31, 2009. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2009		2008	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,238,250**	**$30.86**	1,304,200	$28.02
Granted	**-**	**-**	149,500	44.38
Exercised	**(349,550)**	**18.19**	(215,450)	23.09
Forfeited	**(16,800)**	**46.40**	-	-
Options at end of year	**871,900**	**$35.63**	1,238,250	$30.86

Information about stock options outstanding at December 31, 2009 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$20.65 - $28.65	253,700	1.8	$23.88	253,700	$23.88
$30.25 - $37.12	202,000	5.0	30.31	161,200	30.30
$43.49 - $47.84	416,200	7.1	45.38	168,700	45.32
$20.65 - $47.84	871,900	5.1	$35.63	583,600	$31.85

19. STOCK BASED COMPENSATION PLANS (continued)

In 2009, no options were granted by Canadian Utilities Limited. Options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2009	2008
Contributed surplus at beginning of year	**$2.6**	$1.9
Stock option expense	**0.6**	0.9
Mid-term incentive plan purchases	**-**	(0.2)
Contributed surplus at end of year	**$3.2**	$2.6

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted. During 2009, no options were granted. The weighted average fair value of the options granted in 2008 was $6.71 per option. The following are the weighted average assumptions:

	2009	2008
Risk free interest rate	**No grants**	3.2%
Expected holding period prior to exercise	**No grants**	6.6 years
Share price volatility	**No grants**	18.8%
Estimated annual Class A share dividend	**No grants**	3.0%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting Shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $1.1 million (2008 — $2.0 million income).

20. CHANGES IN NON-CASH WORKING CAPITAL

	2009	2008
Operating activities, changes related to:		
Accounts receivable	**$(24.4)**	$(14.8)
Inventories	**13.8**	(8.2)
Regulatory assets	**23.0**	(12.4)
Prepaid expenses	**(4.8)**	(0.4)
Accounts payable and accrued liabilities	**(43.3)**	9.1
Income taxes payable	**(8.9)**	2.0
Regulatory liabilities	**(10.5)**	11.9
	$(55.1)	$(12.8)
Investing activities, changes related to:		
Accounts receivable	**$ (3.9)**	$ -
Inventories	**4.1**	(1.7)
Prepaid expenses	**-**	1.6
Accounts payable and accrued liabilities	**(29.7)**	37.5
	$(29.5)	$ 37.4
Financing activities, changes related to:		
Accounts receivable	**$ -**	$ (0.1)

21. JOINT VENTURES

The Corporation's interest in joint ventures is summarized below:

	2009	2008
Statement of earnings		
Revenues	**$ 487.2**	$ 609.4
Operating expenses	**281.2**	378.1
Depreciation and amortization	**46.7**	46.9
Interest	**26.9**	31.1
	132.4	153.3
Interest and other income (loss)	**(5.3)**	2.0
Earnings from joint ventures before income taxes	**$ 127.1**	$ 155.3
Balance sheet		
Current assets	**$ 112.7**	$ 191.2
Current liabilities	**(90.2)**	(165.9)
Property, plant and equipment	**768.6**	837.4
Other assets	**27.3**	63.6
Non-recourse long term debt	**(288.3)**	(318.4)
Other non-current liabilities	**(71.0)**	(106.3)
Investment in joint ventures	**$ 459.1**	$ 501.6

21. JOINT VENTURES (continued)

	2009	2008
Statement of cash flows		
Operating activities	**$ 134.3**	$ 185.8
Investing activities	**3.0**	(30.3)
Financing activities	**(150.5)**	(149.7)
Foreign currency translation	**(1.2)**	(2.7)
Increase (decrease) in cash position	**$ (14.4)**	$ 3.1

Current assets include cash of $38.8 million (2008 — $70.3 million) which is only available for use within the joint ventures.

22. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of $1.5 million (2008 — $2.6 million), provided computer operations and systems development services totaling $3.9 million (2008 – $14.1 million), recovered administrative expenses totaling $7.8 million (2008 — $1.5 million) and incurred administrative expenses and corporate signature rights totaling $8.8 million (2008 — $8.9 million). The Corporation incurred no capital expenditures with related parties (2008 — $10.3 million that were recorded in property, plant and equipment).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling $1.4 million (2008 — $1.4 million).

At December 31, 2009, accounts receivable due from related parties amounted to $3.8 million (2008 – $3.3 million) and accounts payable due to related parties amounted to $3.5 million (2008 – $6.6 million).

These transactions are in the normal course of business and under normal commercial terms.

23. EMPLOYEE FUTURE BENEFITS

The Corporation maintains registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

23. EMPLOYEE FUTURE BENEFITS (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2009		2008	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,399.1**	**$ -**	$1,688.6	$ -
Actual return on plan assets	**190.1**	**-**	(236.4)	-
Employee contributions	**3.3**	**-**	3.6	-
Employer contributions	**1.0**	**-**	1.0	-
Benefit payments	**(47.7)**	**-**	(45.5)	-
Payments to defined contribution plans (1)	**(15.0)**	**-**	(12.2)	-
End of year	**$1,530.8**	**$ -**	$1,399.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,399.6**	**$ 57.8**	$1,650.7	$ 79.4
Current service cost	**25.9**	**1.7**	37.1	2.1
Interest cost	**93.6**	**4.2**	91.8	3.8
Employee contributions	**3.3**	**-**	3.6	-
Benefit payments from plan assets (2)	**(47.7)**	**-**	(45.5)	-
Benefit payments by employer	**(4.8)**	**(1.9)**	(4.5)	(2.1)
Experience losses (gains) (3)	**51.3**	**6.2**	(333.6)	(25.4)
End of year (4)	**$1,521.2**	**$ 68.0**	$1,399.6	$ 57.8
Funded status:				
Excess (deficiency) of assets over obligations (4)	**$ 9.6**	**$(68.0)**	$ (0.5)	$(57.8)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**251.4**	**(10.6)**	287.4	(17.2)
Unrecognized net transitional liability (asset)	**(119.4)**	**14.4**	(153.5)	16.5
Accrued asset (liability) (Notes 12, 15)	**$ 141.6**	**$(64.2)**	$ 133.4	$(58.5)
Regulatory asset (liability) (5) (Note 2)	**$ (120.9)**	**$ 51.3**	$ (110.2)	$ 46.9

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

(2) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(3) *A decrease in the liability discount rate at December 31 assumption resulted in the experience losses in 2009 (2008 – an increase in the liability discount rate resulted in experience gains).*

(4) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $76.3 million at December 31, 2009 (2008 – $74.1 million) due to a decrease in the liability discount rate. Apart from these obligations, the excess of assets over obligations for the registered defined benefit pension plans at December 31, 2009 was $85.9 million (2008 – $73.6 million).*

(5) *The regulatory asset (liability) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

23. EMPLOYEE FUTURE BENEFITS (continued)

	2009		2008	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 25.9**	**$ 1.7**	$ 37.1	$ 2.1
Interest cost	**93.6**	**4.2**	91.8	3.8
Actual return on plan assets	**(190.1)**	**-**	236.4	-
Experience losses (gains) on accrued benefit obligations	**51.3**	**6.2**	(333.6)	(25.4)
	(19.3)	**12.1**	31.7	(19.5)
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**78.9**	**-**	(343.6)	-
Unrecognized portion of experience gains on accrued benefit obligations	**(51.3)**	**(6.2)**	333.6	25.4
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**8.4**	**(0.4)**	11.7	-
Amortization of net transitional liability (asset)	**(34.1)**	**2.1**	(34.0)	1.9
	1.9	**(4.5)**	(32.3)	27.3
Defined benefit plans cost (income)	**(17.4)**	**7.6**	(0.6)	7.8
Defined contribution plans cost	**16.2**	**-**	14.1	-
Adjustment to beginning liability	**-**	**-**	-	(10.4)
Total cost (income)	**(1.2)**	**7.6**	13.5	(2.6)
Less: Capitalized	**1.8**	**2.4**	2.0	2.5
Less: Unrecognized defined benefit plans cost (income) [(1)] [(2)]	**(10.4)**	**2.4**	(0.9)	2.4
Net cost (income) recognized [(2)]	**$ 7.4**	**$ 2.8**	$ 12.4	$ (7.5)

(1) *The unrecognized defined benefit plans cost (income) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *Net cost recognized for pension benefit plans in 2009 includes the amortization of $3.9 million (2008 – $3.4 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).*

In the unaudited three months ended December 31, 2009, net cost of $0.6 million (2008 – $3.6 million) was recognized for pension benefit plans and net expense of $0.6 million (2008 – net income of $1.5 million) was recognized for other post employment benefit plans.

23. EMPLOYEE FUTURE BENEFITS (continued)

Weighted average assumptions

	2009		2008	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**7.5%**	**-**	7.0%	-
Liability discount rate for the year	**7.0%**	**7.0%**	5.5%	5.5%
Average compensation increase for the year	**(1)**	**-**	(1)	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**6.4%**	**6.4%**	7.0%	7.0%
Long term inflation rate	**2.0%**	**(2)**	2.5%	(2)

(1) *The assumed average compensation increases are 3.5% for 4 years (2009-2012) and 3.0% thereafter.*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 6.5% for 2009 grading down over 15 years to 4.5% (2008 – 7.2% for 2008 grading down over 5 years to 4.5%), for other medical costs, 4.5% for 2009 and 4.0% thereafter, and for dental costs, 4.0% for 2009 and thereafter (2008 – 4.0% for 2008 and thereafter).*

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2009 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

23. **EMPLOYEE FUTURE BENEFITS** (continued)

	2009 Pension Benefit Plans		2009 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	$(4.0)	-	-
1% decrease [1]	-	$ 4.1	-	-
Liability discount rate				
1% increase [1]	$(50.3)	$(3.2)	$(2.3)	$(0.2)
1% decrease [1]	$ 61.7	$ 5.2	$ 2.8	$ 0.3
Future compensation rate				
1% increase [1]	$ 12.0	$ 1.9	-	-
1% decrease [1]	$(11.1)	$(1.7)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 48.9	$ 5.8	$ 2.1	$ 0.4
1% decrease [1] [3]	$(41.6)	$(5.2)	$(1.8)	$(0.3)

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Pension benefit plan assets

	2009		2008	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 842.6**	**55.0**	$ 755.5	54.0
Fixed income securities [2]	**584.1**	**38.2**	526.9	37.7
Real estate [3]	**90.1**	**5.9**	90.8	6.5
Cash and other assets [4]	**14.0**	**0.9**	25.9	1.8
	$1,530.8	**100.0**	$1,399.1	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2009, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $146.4 million and $151.1 million, respectively (2008 – $150.8 million and $136.8 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

23. EMPLOYEE FUTURE BENEFITS (continued)

At December 31, 2009, plan assets include long term debt of CU Inc. having a market value of \$15.1 million (2008 – \$13.9 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$17.8 million (2008 – \$16.1 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of \$17.0 million (2008 – \$13.8 million).

Funding

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

The Corporation has not made material contributions since April 1, 1996 due to the defined benefit plans' surplus position. Declines in stock and bond markets combined with increasing liabilities due to changes in actuarial assumptions and additional employee service have created funding deficits. Actuarial valuations are expected to be completed by May 2010. Based on the information currently available, the funding contributions for 2010 are expected to be in the range of \$75.0 million to \$90.0 million.

For the purposes of any funding requirements pertaining to utility operations the Corporation includes the cost of funding in its rate applications to the AUC and has filed a pension common matters application with the AUC requesting deferral accounts for 2010. Based on the assumption that the AUC will allow full recovery of these costs, the net funding contributions are expected to be in the range of \$15.0 million to \$20.0 million.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to share owners, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Energy segment is affected by the cost of natural gas, the price of natural gas liquids and the price of electricity in the Province of Alberta and the United Kingdom. In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2009, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of long term debt and non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts that were not considered own-use contracts.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The derivative assets and liabilities comprise the following:

	2009	2008
Derivative assets – current:		
Interest rate swap agreements	**$ 1.2**	$ -
Foreign currency forward swaps	**-**	1.7
	$ 1.2	$ 1.7
Derivative assets – non-current:		
Natural gas purchase contracts	**$26.0**	$60.1
Interest rate swap agreements	**5.4**	-
Foreign currency forward swaps	**-**	0.3
	$31.4	$60.4
Derivative liabilities – current:		
Interest rate swap agreements	**$ 2.4**	$ 5.4
Foreign currency forward swaps	**0.5**	-
	$ 2.9	$ 5.4
Derivatives liabilities – non-current:		
Interest rate swap agreements	**$ 5.9**	$12.4

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Interest rate risk

The Corporation's interest-bearing assets and liabilities include cash and short-term investments, bank indebtedness, long term debt and non-recourse long term debt. The interest rate risk faced by the Corporation is largely a result of its non-recourse long term debt at variable rates and cash and short term investments. The Corporation has converted certain variable rate long term debt and non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Financing	Swap Fixed Interest Rate [(1)]	Variable Debt Interest Rate	Maturity Date	Notional Principal 2009	Notional Principal 2008
ATCO Frontec (see Note 4): (2008 - €20.8 million)	5.457%	90 day Euribor	October 2010	**$ -**	$ 35.5
Karratha: ($100.0 million AUD)	5.710%	Bank Bill Rate in Australia	June 2015	**94.4**	-
Osborne: ($21.0 million AUD (2008 - $24.9 million AUD))	7.433%	Bank Bill Rate in Australia	December 2013	**19.7**	21.3
APALP:	7.750%	6 month LIBOR	December 2011	**40.7**	61.7
Joffre:	7.536%	90 day BA	September 2012	**11.5**	15.6
Scotford:	3.328%	90 day BA	November 2013	**27.8**	32.6
	3.726%	3 month LIBOR	November 2013	**7.0**	8.2
Muskeg River:	5.553%	90 day BA	December 2012	**22.5**	26.1
	5.653%	3 month LIBOR	December 2012	**5.6**	6.5
Brighton Beach:	5.867%	90 day BA	June 2009	**-**	8.0
	6.700%	90 day BA	March 2019	**30.0**	32.2
	4.578%	90 day BA	June 2020	**4.2**	-
	4.784%	3 month LIBOR	June 2020	**3.8**	-
Cory:	6.591%	90 day BA	June 2011	**0.9**	1.5
				$268.1	$249.2

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate
Euribor – Euro Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 14).

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 95% (2008 — 97%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre and APALP interest rate swaps, are recorded in other comprehensive income. Changes in the fair value of the Joffre and APALP interest rate swaps were $0.7 million and $1.4 million, respectively, which were recognized in earnings. In the fourth quarter of 2008, the APALP interest rate swap became ineffective. Up to that point, the swap had been highly effective and therefore changes in the fair value were recorded in other comprehensive income. After this, changes in the fair value have been recorded in earnings.

The Corporation's cash and short term investments include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Corporation has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

Foreign currency exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income.

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.S. dollars. At December 31, 2009, the contracts consist of purchases of $0.2 million U.S. in return for Canadian dollars and $2.8 million U.S. in return for Australian dollars (2008 — purchases of $0.5 million U.S. in return for Canadian dollars and $10.7 million U.S in return for Australian dollars).

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.0 million, net of income taxes, for the unaudited three months ended December 31, 2009 (2008 – $1.1 million) and decreased earnings by $7.4 million, net of income taxes, for the year ended December 31, 2009 (2008 –

$2.0 million). At December 31, 2009, the natural gas purchase contracts derivative asset is $26.0 million (2008 – $60.1 million), a net change of $34.1 million, and the power generation revenue contract liability is $20.4 million (2008 – $44.6 million), a net change of $24.2 million.

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments. Approximately 80% of the short term investments at December 31, 2009 were invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties. A significant portion of loans and receivables arise from the Corporation's operations in Alberta.

Accounts receivable credit risk is reduced by a large and diversified customer base, requirement for of credit security such as letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates and the ability to request recovery through customer rates any losses from retailers beyond that covered by the retailer security provided in accordance with provincial regulations.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2009, the provision for impairment of credit losses was $1.5 million. The changes in the provision for impairment were as follows:

	2009
Provision at beginning of year	$ 1.9
Adjustment due to ATCO Structures & Logistics transaction (Note 4)	(0.5)
Impairment of receivables	0.2
Receivables written off as uncollectible	(0.1)
Provision at end of year	$ 1.5

At December 31, 2009, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2009
30 to 90 days	$3.8
Greater than 90 days	0.9
	$4.7

No other impairments have been identified within accounts receivable.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities.

The Corporation has contractual obligations in the normal course of business; future minimum undiscounted contractual maturities are as follows:

	2010	2011	2012	2013	2014	2015 and thereafter
Accounts payable and accrued liabilities	$ 382.1	$ -	$ -	$ -	$ -	$ -
Operating leases [1]	18.6	16.4	13.0	12.0	10.7	38.0
Long term debt (Note 14)	127.8	107.6	138.4	50.7	138.4	2,557.5
Non-recourse long term debt (Note 14)	49.0	42.8	40.5	36.9	33.2	205.7
Interest expense (Note 14)	225.1	205.1	199.0	188.4	185.0	2,056.6
Purchase obligations:						
Coal purchase contracts [2]	51.1	52.3	53.9	55.5	57.1	242.8
Natural gas purchase contracts [3]	37.8	12.8	13.1	6.9	0.4	-
Operating and maintenance agreements [4]	19.3	18.7	16.5	17.8	20.3	45.0
Capital expenditures [5]	90.9	-	-	-	-	-
Derivatives [6]	5.6	3.3	2.1	1.3	1.1	2.1
Other	0.8	0.3	0.3	0.2	0.2	0.2
	$1,008.1	$459.3	$476.8	$369.7	$446.4	$5,147.9

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*
(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*
(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*
(4) *ATCO Power and Alberta Power (2000) have long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.*
(5) *Various contracts to purchase goods and services with respect to capital expenditures.*
(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2009.*

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of non-derivative financial instruments

The carrying values and fair values of the Corporation's non-derivative financial instruments are as follows:

	2009		2008	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Held For Trading:				
Cash [1]	**$ 104.2**	**$ 104.2**	$ 31.7	$ 31.7
Held to Maturity:				
Short term investments [1]	**691.8**	**691.8**	716.9	716.9
Loans and Receivables:				
Accounts receivable [1]	**366.4**	**366.4**	385.5	385.5
Lease receivable [2]	**59.1**	**59.1**	-	-
Financial Liabilities				
Held For Trading:				
Bank indebtedness [1]	**-**	**-**	22.0	22.0
Other Liabilities:				
Accounts payable and accrued liabilities[3]	**382.1**	**382.1**	479.5	479.5
Liabilities to customers for future income taxes (see Note 15) [3]	**12.1**	**12.1**	19.2	19.2
Long term debt [4]	**3,105.1**	**3,397.4**	2,862.0	2,879.1
Non-recourse long term debt [4]	**403.8**	**438.8**	457.2	489.1

(1) Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments and negligible credit losses.

(2) Recorded at amortized cost. Fair value approximates the carrying amount as the lease receivable has been recorded at the present value of future minimum lease payments and negligible credit losses.

(3) Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.

(4) Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

The fair values of the Corporation's derivative financial instruments are as follows:

	2009			2008		
	Notional Principal[1]	**Fair Value Receivable (Payable)[3]**	**Maturity**	Notional Principal[1]	Fair Value Receivable (Payable)[3]	Maturity
Held For Trading:						
Interest rate swaps	**$268.1**	**$ (1.7)**	**2010-2019**	$249.2	$(17.8)	2009-2019
Foreign currency forward contracts	**$ 3.4**	**$ (0.5)**	**2010**	$ 12.3	$ 2.0	2009-2010
Natural gas purchase contracts	**N/A [2]**	**$26.0**	**2014**	N/A [2]	$ 60.1	2014

(1) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(2) *The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts.*

(3) *Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.*

Fair value of financial instruments

The hierarchy of the Corporation's financial instruments measured at fair value is as follows (see Note 1 for description of hierarchy):

	Level 1	Level 2	Level 3	Total
Derivative assets	$ -	$6.6	$26.0	$32.6
Derivative liabilities	-	(8.8)	-	(8.8)
	$ -	$(2.2)	$26.0	$23.8

Amounts included in Level 3 relate to the natural gas purchase contracts described previously. The changes in amounts classified in Level 3 are as follows:

	2009
Balance at beginning of year	**$ 60.1**
Total gains (losses) recognized in earnings	**(34.1)**
Purchases, sales, issues, and settlements	**-**
Transfers into (out of) Level 3	**-**
Balance at end of year	**$ 26.0**

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Sensitivity analysis

The analysis below illustrates the extent to which the Corporation's results are impacted by financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk). Non-derivative financial instruments (listed on the previous page) are recorded at cost and these carrying amounts are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian, Australian and Euribor interest rates, the foreign currency exchange rates of the Canadian dollar to the U.S. dollar, the Australian dollar to the U.S. dollar and the forward price of natural gas. The analysis excludes the impact that changes in the underlying market risks would have on non-financial assets and liabilities, foreign currency translation of self-sustaining foreign operations included in accumulated other comprehensive income, and carrying value of employee future benefits. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are highly effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Balance sheet sensitivity to interest rates and foreign currency exchange rates relates only to derivative instruments. There are no available for sale financial assets and other liabilities are carried at amortized cost, in which case the carrying values are not affected by changes in interest rates and foreign currency exchange rates.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset and the corresponding adjustment for the associated power generation revenue contract liability.

	2009	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	$ 0.1	$ 0.6
25 basis points decrease	$(0.1)	$(0.6)
Australian interest rates		
25 basis points increase	$ -	$ 0.8
25 basis points decrease	$ -	$(0.8)
Australian dollar to U.S. dollar exchange rate		
10% increase	$ -	$ 0.3
10% decrease	$ -	$(0.3)
U.S. dollar to Canadian dollar exchange rate		
10% increase	$ 1.5	$ -
10% decrease	$(1.5)	$ -
Forward price of natural gas		
10% increase	$ 1.5	$ -
10% decrease	$(1.5)	$ -

25. OTHER COMPREHENSIVE INCOME

Other comprehensive income ("OCI") of the Corporation is comprised of two components: the unrealized gains and losses on effective cash flow hedging instruments and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	2009	2008
Accumulated OCI at beginning of period:		
Cash flow hedge losses [(1)]	**$(11.5)**	$ (4.6)
Foreign currency translation adjustment	**(43.6)**	(28.5)
	(55.1)	(33.1)
Adjustment to accumulated OCI from the ATCO Structures & Logistics Transaction (see Note 4):		
Cash flow hedge losses [(2)]	**0.2**	-
Foreign currency translation adjustment	**(1.3)**	-
	(1.1)	-
OCI for the period:		
Changes in fair values of cash flow hedges [(3)]	**7.4**	(7.7)
Transfers of cash flow hedge losses to earnings [(4)]	**0.9**	0.8
	8.3	(6.9)
Foreign currency translation adjustment	**(6.1)**	(15.1)
	2.2	(22.0)
Accumulated OCI at end of period:		
Cash flow hedge losses [(5)]	**(3.0)**	(11.5)
Foreign currency translation adjustment	**(51.0)**	(43.6)
	$(54.0)	$(55.1)

(1) *Net of income taxes of $4.2 million and $1.9 million, respectively.*
(2) *Net of income taxes of $(0.1) million.*
(3) *Net of income taxes of $(3.2) million and $2.3 million, respectively.*
(4) *Net of income taxes of nil.*
(5) *Net of income taxes of $0.9 million and $4.2 million, respectively.*

26. CONTINGENCIES

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AUC.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to DEML contemplated under the transaction agreements.

27. SEGMENTED INFORMATION

Description of segments

In the third quarter of 2009, the Corporation reorganized its operating subsidiaries into the following segments: Utilities, Energy, and Corporate & Other. Comparative amounts for prior periods have been restated to reflect the realigned segments.

The **Utilities** segment includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission of natural gas by ATCO Pipelines, and the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

27. **SEGMENTED INFORMATION** (continued)

The **Energy** segment includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the non-regulated natural gas gathering, processing, storage, and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** segment includes the Corporation's equity investment in ATCO Structures & Logistics, the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek. The cash balances and commercial real estate owned by the Corporation in Alberta are also included in this segment.

Segmented results – Three months ended December 31

2009 2008 *(Unaudited)*	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$361.8**	**$294.7**	**$ 19.1**	**$ -**	**$675.6**
	$323.7	$325.4	$ 95.2	$ -	$744.3
Revenues – intersegment[1]	**6.1**	**1.4**	**33.6**	**(41.1)**	**-**
	6.7	9.6	33.6	(49.9)	-
Revenues	**$367.9**	**$296.1**	**$ 52.7**	**$(41.1)**	**$675.6**
	$330.4	$335.0	$ 128.8	$(49.9)	$744.3
Earnings attributable to Class A and Class B shares	**$ 52.8**	**$ 72.5**	**$ 1.7**	**$ 0.1**	**$127.1**
	$ 45.3	$ 65.9	$ 3.5	**$ (0.2)**	$114.5

[1] *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

27. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2009 2008	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,342.8** $1,235.1	**$1,021.9** $1,214.3	**$ 219.3** $ 329.5	**$ -** $ -	**$2,584.0** $2,778.9
Revenues – intersegment (1)	**24.7** 25.8	**9.5** 28.4	**125.6** 117.8	**(159.8)** (172.0)	**-** -
Revenues	**1,367.5** 1,260.9	**1,031.4** 1,242.7	**344.9** 447.3	**(159.8)** (172.0)	**2,584.0** 2,778.9
Operating expenses	**772.2** 718.7	**591.5** 745.8	**262.4** 341.4	**(161.1)** (170.4)	**1,465.0** 1,635.5
Depreciation and amortization	**192.4** 248.3	**116.8** 110.6	**20.5** 28.3	**-** -	**329.7** 387.2
Interest expense	**175.5** 157.5	**64.2** 72.6	**201.7** 190.7	**(199.8)** (187.3)	**241.6** 233.5
Gain on ATCO Structures & Logistics transaction	**-** -	**-** -	**(33.9)** -	**-** -	**(33.9)** -
Earnings from investment in ATCO Structures & Logistics	**-** -	**-** -	**(7.8)** -	**-** -	**(7.8)** -
Interest and other income	**(24.0)** (25.5)	**(15.4)** (12.3)	**(203.7)** (208.6)	**199.8** 187.3	**(43.3)** (59.1)
Earnings before income taxes	**251.4** 161.9	**274.3** 326.0	**105.7** 95.5	**1.3** (1.6)	**632.7** 581.8
Income taxes	**37.9** 3.4	**63.4** 101.6	**23.7** 30.3	**0.4** (0.5)	**125.4** 134.8
	213.5 158.5	**210.9** 224.4	**82.0** 65.2	**0.9** (1.1)	**507.3** 447.0
Dividends on equity preferred shares	**18.1** 9.9	**1.4** 1.4	**21.2** 21.2	**-** -	**40.7** 32.5
Earnings attributable to Class A and Class B shares	**$ 195.4** $ 148.6	**$ 209.5** $ 223.0	**$ 60.8** $ 44.0	**$ 0.9** $ (1.1)	**$ 466.6** $ 414.5
Total assets	**$5,921.9** $4,739.3	**$2,357.1** $2,302.8	**$791.0** $811.4	**$ 13.6** $ 6.5	**$9,083.6** $7,860.0
Capital expenditures (2)	**$ 776.1** $ 852.6	**$ 151.5** $ 109.7	**$ 18.5** $ 48.6	**$ -** $ -	**$ 946.1** $1,010.9

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*
(2) *Includes purchases of property, plant and equipment and intangibles.*

27. **SEGMENTED INFORMATION** (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues	**$2,290.6**	$2,396.2	**$293.4**	$382.7	**$2,584.0**	$2,778.9
Property, plant and equipment and intangibles	**$6,639.4**	$5,909.5	**$335.1**	$307.4	**$6,974.5**	$6,216.9

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Year Ended December 31, 2009

This MD&A should be read in conjunction with the Corporation's unaudited consolidated financial statements for the three months ended December 31, 2009, and the audited consolidated financial statements for the year ended December 31, 2009. This MD&A is dated February 17, 2010. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section for a description of these items (non-GAAP item).

Adjusted Earnings per Class A and Class B Share is calculated by dividing Adjusted Earnings for a period by the weighted average number of Class A and Class B Shares outstanding during the period (non-GAAP item).

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

ASL means ATCO Structures & Logistics Ltd., the company formed on July 1, 2009 through the amalgamation of ATCO Structures and ATCO Frontec.

ATCO Energy Solutions means ATCO Energy Solutions Ltd.

ATCO Frontec means ATCO Frontec Corp., the wholly-owned subsidiary of Canadian Utilities Limited which amalgamated with ATCO Structures on July 1, 2009 to form ATCO Structures & Logistics Ltd.

ATCO Noise Management means ATCO Noise Management Ltd., the wholly-owned subsidiary of ATCO that became a wholly-owned subsidiary of ATCO Structures & Logistics Ltd. on July 1, 2009 and was subsequently amalgamated with ATCO Structures & Logistics Ltd. on January 1, 2010.

ATCO Structures means ATCO Structures Inc., the wholly-owned subsidiary of ATCO Ltd. which amalgamated with ATCO Frontec on July 1, 2009 to form ATCO Structures & Logistics Ltd.

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Cap and Trade means a form of market emission control regulation whereby permits must be surrendered for environmental emissions. A specified number of permits are created (the cap) and distributed. These can be traded amongst market participants to meet their compliance needs. The intended result is that environmental emissions bear a cost associated with obtaining the requisite permits and that creates a financial incentive to reduce the emissions.

Carbon Rate Riders means customer rate riders that were approved in the past by the AUC to distribute net revenues related to the Carbon Natural Gas Storage Facility to customers.

Class A Shares means Class A non-voting shares of the Corporation.

Class B Shares means Class B common shares of the Corporation.

Corporation means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac Spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

GHG means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

Mark-to-market means assigning a value to a contract or financial instrument based on the current market prices for that contract or instrument or similar contracts or instruments.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

OPEB means other post employment benefits, which principally include health, dental and life insurance payments for retirees and their dependants.

Petajoule (PJ) means a unit of energy equal to approximately 948.2 billion British thermal units.

Placeholder means an AUC approved interim cost which has been included in utility customer rates pending an AUC review in a separate or future proceeding. This cost is subject to adjustment once the separate or future proceeding is completed and may result in refunds to or recoveries from customers.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC.

Propane Plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark Spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, Spark Spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

U.K. means United Kingdom.

U.S. means United States of America.

Company Overview

Alberta-based Canadian Utilities Limited, an ATCO Company, with more than 5,700 employees and assets of approximately $9.1 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquid extraction) and Technologies (business systems solutions).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

REALIGNMENT OF SEGMENTS

Starting in the third quarter of 2009, the Corporation reorganized its operating subsidiaries into the following segments: Utilities, Energy and Corporate & Other.

These new segments are the basis for disclosure in this MD&A. Comparative amounts for the previous year have been restated to conform to these new segments.

The **Utilities** Segment includes:
- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission of natural gas by ATCO Pipelines; and
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

The **Energy** Segment includes:
- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by Alberta Power (2000); and
- the non-regulated natural gas gathering, processing, storage and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** Segment includes
- the Corporation's 24.5% equity investment in ATCO Structures & Logistics Ltd. (refer to Company Overview – Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section);
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- cash balances and commercial real estate owned by the Corporation in Alberta.

Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information. For additional information on the Corporation's segments, refer to Note 27 to the consolidated financial statements.

Prior to the third quarter of 2009, the Corporation operated in the following segments:

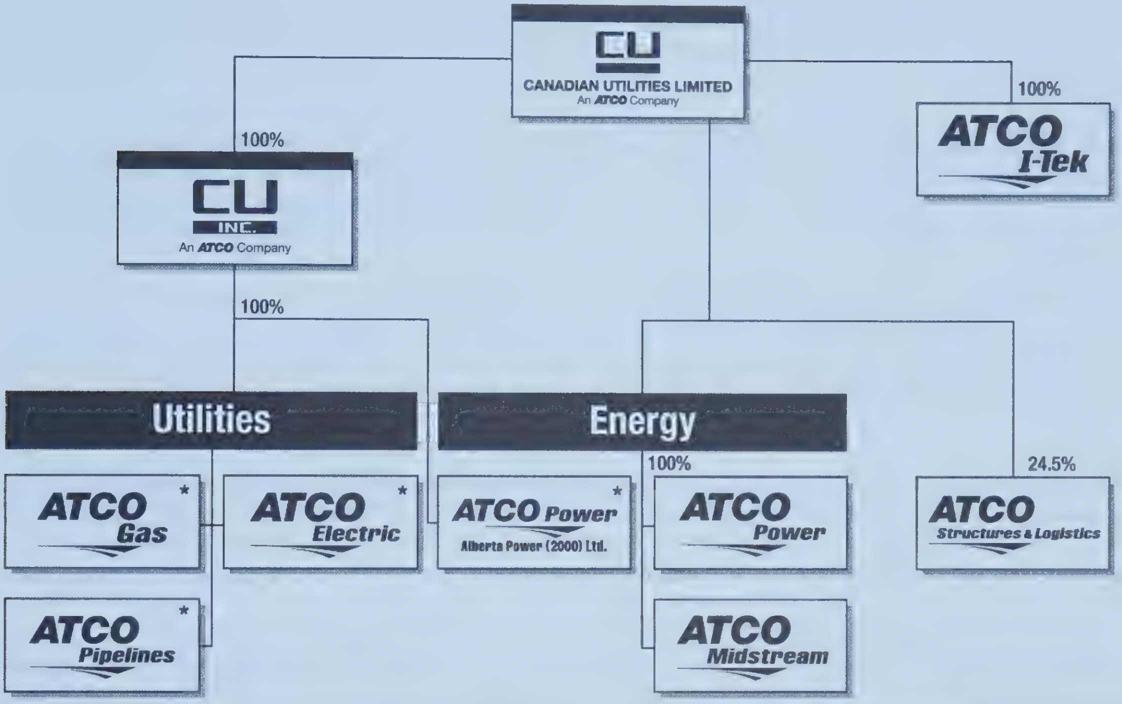
The **Utilities** Segment included ATCO Gas, ATCO Pipelines and ATCO Electric.

The **Power Generation** Segment included ATCO Power and Alberta Power (2000).

The **Global Enterprises** Segment included ATCO Midstream, ATCO Frontec and ATCO I-Tek.

The **Corporate & Other** Segment included cash balances and commercial real estate owned by the Corporation in Alberta.

Simplified Organizational Structure



** Regulated operations include ATCO Gas, ATCO Electric, ATCO Pipelines and the generating plants of Alberta Power (2000) Ltd.*

APPOINTMENT OF NEW SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

On November 12, 2009 the Corporation announced that Brian R. Bale had been appointed Senior Vice President and Chief Financial Officer for the Corporation effective December 1, 2009. Brian R. Bale, previously Senior Vice President, Finance and Regulatory, ATCO Gas, replaced Karen M. Watson who retired after thirty three years of service to the ATCO Group.

TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent ATCO Ltd. finalized a transaction combining ATCO Frontec, a wholly-owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO Ltd. (ATCO Structures & Logistics Transaction). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics Ltd. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

This was a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation; with an after tax gain for accounting purposes of $29.6 million recorded on closing.

Prior to the ATCO Structures & Logistics Transaction, the Corporation consolidated ATCO Frontec as it was a wholly-owned subsidiary. Therefore, all revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation for the period up to June 30, 2009.

From July 1, 2009, the Corporation records an equity accounted for investment for its 24.5% interest in ASL as it retains significant influence. This is reflected as a single line item called "Earnings from investment in ATCO Structures & Logistics" on the consolidated statement of earnings and a single line item called "Investment in ATCO Structures & Logistics" on the consolidated balance sheet. The "Investment in ATCO Structures & Logistics" is increased or decreased to include the Corporation's share of earnings and capital transactions from July 1, 2009 onward.

As a result of the ATCO Structures & Logistics Transaction, the consolidated statement of earnings for the Corporation is comprised of a combination of revenues and expenses of ATCO Frontec from January 1 to June 30, 2009, and Earnings from investment in ATCO Structures & Logistics from July 1 to December 31, 2009. The consolidated balance sheet of the Corporation at December 31, 2009 no longer includes assets and liabilities of ATCO Frontec. The balance sheet reflects an Investment in ATCO Structures & Logistics representing the Corporation's ownership interest in ASL. Amounts included in the consolidated statement of cash flows and consolidated statement of comprehensive earnings follow the same treatment as the consolidated statement of earnings.

ATCO Frontec was previously included in the Global Enterprises Segment. As a result of the realignment of segments (refer to Company Overview – Realignment of Segments section), all amounts relating to ATCO Frontec, for the six months ended June 30, 2009 and for the three months and year ended December 31, 2008, have been re-classified to the Corporate & Other Segment. This is consistent with the inclusion of the Corporation's 24.5% equity investment in ASL in the Corporate & Other Segment.

The transaction allows ATCO Frontec, ATCO Structures and ATCO Noise Management to pursue a more efficient working relationship in response to changing global markets. ATCO Structures manufactured, sold and leased workforce housing and modular buildings around the world. ATCO Noise Management provided acoustical consulting services and turnkey noise control for industrial facilities, addressing environmental impact and worker exposure from noise. ATCO Frontec specialized in the rapid mobilization and delivery of site support and camp services to the resource, defence and telecommunications sectors. The new company, ASL, continues these activities and will provide customers with solutions and logistics support for facilities, catering, housing, construction and site management.

CARBON NATURAL GAS STORAGE FACILITY

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta (Carbon Facility). Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon Facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation.

As a result of numerous regulatory and legal proceedings, ATCO Gas has removed the Carbon Facility from regulation for accounting purposes in the third quarter of 2009. Furthermore, ATCO Gas has received approval from the AUC to suspend customer rate riders (Carbon Rate Riders) that were approved in the past to distribute net revenues related to the Carbon Facility to customers.

The financial impacts of these developments recorded in the third quarter of 2009 are as follows:

- ATCO Gas removed the Carbon Facility from regulation. As a result, ATCO Gas has derecognized all previously recorded regulatory assets and liabilities relating to the Carbon Facility as these amounts are no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by $1.9 million.
- ATCO Gas recognized increased revenues of $13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008 to June 30, 2008 which was previously refunded to customers and decreased revenues of $7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net increase to ATCO Gas' earnings as a result of this was $4.5 million.

ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of $20.5 million, excluding interest, related to the removal of the Carbon Facility from regulation for the period April 1, 2005 to December 31, 2007. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas.

For a more detailed summary of the items related to the Carbon Facility refer to Segmented Information – Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section.

FINANCIAL MARKETS

Over the last year, significant challenges have been experienced in domestic and international financial markets. These challenges have an impact on the ability of certain borrowers to finance existing operations and capital expenditure programs.

As discussed elsewhere in this MD&A, the Utilities Segment has a capital expenditure program of approximately $3.5 billion to $4.5 billion over the next three years. While the current financial situation has not directly impacted the Corporation's ability to fund this capital expenditure program and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and preferred equity capital.

The Corporation is unable to determine what future changes in the financial markets could occur and how these changes could affect the Corporation. Deterioration in domestic and international economic activity may impact the operations of the Corporation.

COMMODITY AND ENERGY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Corporation's operations, particularly the lower average Frac Spreads for 2009 on ATCO Midstream's NGL business and the decline in the resource sector on ASL.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 437 MW of merchant power capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and 70 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 262 MW.

The Corporation is unable to determine what future changes in commodity and energy markets could occur and how these changes could affect the Corporation.

PENSION PLANS

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. The Corporation has not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus positions which existed in the past and were being used to fund the employer's contributions to the defined contribution component of the pension plans. Based on these changes material current service and deficit funding contributions will resume in 2010. The Corporation has applied to the AUC to recover the utility portion of the funding contributions from utility customers. For further information refer to Business Risks – Pension Plans section.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Non-GAAP Measures

The Corporation uses the measures "funds generated by operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B Share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital. In management's opinion, funds generated by operations is a significant performance indicator of the Corporation's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings is defined as earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B Shares is presented in the Results of Operations – Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2009, the Corporation's management evaluated the effectiveness of the Corporation's disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Corporation's management, inclusive of the CEO and the CFO, does not expect that the Corporation's disclosure controls and procedures will prevent or detect all errors and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Corporation have been detected.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's disclosure controls and procedures are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the CEO and the CFO by others within those entities on a timely basis.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2009, the Corporation's management evaluated the effectiveness of the Corporation's internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning on October 1, 2009, and ended on December 31, 2009, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and % return on equity) (1) (2) (7)	For the Year Ended December 31 2009	2008	2007
Revenues	**2,584.0**	2,778.9	2,404.9
Earnings attributable to Class A and Class B shares	**466.6**	414.5	383.9
Adjusted Earnings (3)	**427.6**	403.2	341.0
Total assets	**9,083.6**	7,860.0	7,299.7
Long term debt	**3,102.3**	2,844.3	2,603.2
Non-recourse long term debt	**354.8**	412.4	478.1
Equity preferred shares	**785.0**	625.0	625.0
Class A and Class B share owners' equity	**3,046.1**	2,748.5	2,517.1
Return on equity	**16.1**	15.7	15.9
Cash flow from operations	**738.3**	783.7	669.6
Funds Generated by Operations	**793.4**	796.5	688.6
Capital expenditures	**946.1**	1,010.9	700.8
Earnings per Class A and Class B share	**3.71**	3.30	3.06
Diluted earnings per Class A and Class B share	**3.71**	3.29	3.05
Adjusted Earnings per Class A and Class B share (3)	**3.40**	3.21	2.72
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (4)	**1.09**	1.09	1.13
Series Q (5)	**-**	-	0.68
Series R (5)	**-**	-	0.61
Series S (5)	**-**	-	0.77
Series T (4)	**1.09**	1.09	1.09
Series U (4)	**1.09**	1.09	1.09
Series V (6)	**1.18**	1.18	1.28
Series W	**1.45**	1.45	1.45
Series X	**1.50**	1.50	1.50
Class A and Class B share	**1.41**	1.33	1.25
Equity per Class A and Class B share	**24.20**	21.90	20.09
Class A and Class B shares outstanding, year end (thousands)	**125,860**	125,510	125,295
Weighted average Class A and Class B shares outstanding (thousands):			
Basic	**125,637**	125,408	125,409
Diluted	**125,774**	125,784	125,934

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *The above data (other than Adjusted Earnings, Adjusted Earnings per Class A and Class B share, Funds Generated by Operations, Return on equity and Equity per Class A and Class B share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

(3) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

(4) *The dividend rate was reset to $1.09 (from 5.05% to 4.35%) for the period between December 2, 2006, and December 2, 2011.*

(5) *Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.*

(6) *The dividend rate was reset to $1.18 (from 5.25% to 4.70%) for the period between October 3, 2007, and October 3, 2012.*

(7) *Certain numbers have been restated to reflect changes in accounting policies relating to rate regulated operations and goodwill and intangible assets (refer to Changes in Accounting Policies – Rate Regulated Operations and Goodwill and Intangible Assets sections).*

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B Shares after adjustments for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

	For the Year Ended December 31	
($ millions)	**2009**	2008
Earnings attributable to Class A and Class B Shares	**466.6**	414.5
Mark-to-Market Adjustment (1)	**7.4**	2.0
H.R. Milner Income Tax Reassessment (2)	**(16.8)**	-
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management (3)	**(29.6)**	-
Other Post Employment Benefits (4)	**-**	(7.0)
Federal Court of Appeal Decision- Mining Assets (5)	**-**	(3.0)
2008 Tax Assessment (6)	**-**	(3.3)
Adjusted Earnings	**427.6**	403.2

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following significant non-operating financial items.

(1) Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability (Mark-to-Market Adjustment)

ATCO Power has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts expire in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation does not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset.

This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.0 million, net of income taxes, for the three months ended December 31, 2009 (2008 – decrease of $1.1 million) and decreased earnings by $7.4 million, net of income taxes, for the year ended December 31, 2009 (2008 – decrease of $2.0 million). At December 31, 2009, the natural gas purchase contracts derivative asset was $26.0 million (2008 – $60.1 million) and the power generation revenue contract liability was $20.4 million (2008 – $44.6 million).

(2) H.R. Milner Income Tax Reassessment

In 2006, Canada Revenue Agency (CRA) issued an income tax reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The Corporation disagreed with CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Corporation's favour, the Corporation made a $28.8 million payment and reduced earnings by $12.4 million in 2006.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering CRA to reverse its 2006 reassessment of Alberta Power (2000)'s 2001 tax return. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA.

The impact of the judgment is a $13.7 million recovery of income tax and related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) will receive interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments have resulted in an $16.8 million increase in earnings which was recorded in the third quarter of 2009. In total, Alberta Power (2000) is entitled to refunds of approximately $28.0 million including interest and net of consequential adjustments to other taxation years arising from the judgment. Of this amount, the CRA has refunded $20.8 million as of December 31, 2009, and approximately $7.2 million remains outstanding from the Government of Alberta.

(3) Gain on Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management

On July 1, 2009, the Corporation finalized the ATCO Structures & Logistics Transaction which resulted in an after tax gain of $29.6 million (refer to Company Overview – Transaction To Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section).

(4) Other Post Employment Benefits

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the 2008 OPEB liability for the regulated subsidiaries increased by $10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for OPEB plans as paid. Consequently, there was no change to their 2008 earnings. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The 2008 OPEB liability for the non-regulated subsidiaries decreased which resulted in an increase to earnings after income taxes of $7.0 million, of which $5.5 million was recorded in the second quarter of 2008, and $1.5 million was recorded in the fourth quarter of 2008.

The 2008 earnings impact of the OPEB adjustment by segment was as follows:

($ millions)	Years Prior to 2008
Energy	3.9
Corporate & Other and Intersegment Eliminations	3.1
Total	7.0

(5) Federal Court of Appeal Decision – Mining Assets

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous CRA reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the ATCO Group's coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric, and Alberta Power (2000) (as successor to ATCO Electric in the coal-fired generating plants), to claim additional resource allowance and capital cost allowance. ATCO Electric and Alberta Power (2000) have recorded a reduction in current income tax expense and a decrease in interest expense which resulted in increases to the Corporation's earnings of $3.0 million for the year ended December 31, 2008.

The earnings impact of this Federal Court of Appeal Tax Decision by segment was as follows:

($ millions)	Total
Utilities	2.2
Energy	0.8
Total	3.0

(6) 2008 Tax Assessment

In 2008 the Corporation received a favourable tax decision from the CRA to treat certain previously reported capital outlays as current expenditures for tax purposes in ATCO Electric and ATCO Pipelines. As a result the Corporation recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of $3.3 million.

CONSOLIDATED REVENUES AND EARNINGS

Revenues in 2009 **decreased** by $194.9 million (7%) compared to 2008. This decrease was primarily attributable to a $211.3 million (17%) decrease in the Energy Segment and a $102.4 million (23%) decrease in the Corporate & Other Segment, partially offset by a $106.6 million (8%) increase in the Utilities Segment.

The **decrease** in **revenues** was primarily due to the impact of the ATCO Structures & Logistics Transaction, lower merchant performance in ATCO Power's Alberta generating plants due to lower pool prices in the Alberta electricity market and lower exchange rates on conversion of U.K. revenues into Canadian dollars in ATCO Power's U.K. operations. Also contributing to the decrease in revenues were lower NGL prices and volumes and lower sales of natural gas purchased for third parties in ATCO Midstream and the impact of applying new accounting standards in the Utilities Segment relating to the recognition of revenues for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section), increased storage revenues in ATCO Midstream due to the timing and demand for natural gas storage and higher AUC approved customer rates resulting from the ATCO Pipelines' negotiated settlement decision for 2008 and 2009 (ATCO Pipelines' Negotiated Settlement).

Earnings in 2009 were $466.6 million, an **increase** of $52.1 million (13%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were $427.6 million, an **increase** of $24.4 million (6%) over 2008. The primary reasons for increased Adjusted Earnings were the timing and demand for natural gas storage in ATCO Midstream, the impact of the ATCO Pipelines' Negotiated Settlement, lower operating and maintenance costs as compared to amounts that were included in ATCO Electric's and ATCO Gas' customer rates primarily due to cost efficiencies, the impact of increased rate base in ATCO Electric and ATCO Gas and the impact of the removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section). These increases were partially offset by lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market and the 2008 recognition of insurance proceeds from the 2007/2008 Barking outage in ATCO Power's U.K. operations and lower margins and volumes for NGL extraction in ATCO Midstream.

Interest and other income in 2009 **decreased** by $15.8 million to $43.3 million compared to 2008, mainly due to lower rates of interest earned on cash balances and the mark-to-market adjustment in ATCO Power, partially offset by interest income recognized on the H.R. Milner Income Tax Reassessment in Alberta Power (2000) (recovery of $7.5 million paid on the original 2006 income tax assessment and $5.0 million of interest income pertaining to subsequent years) (refer to Annual Results of Operations – Significant Non-Operating Financial Items – H.R. Milner Income Tax Reassessment section).

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	**23.2**	37.9	(39%)
Purchased power	**54.1**	54.1	0%
Operation and maintenance	**965.5**	1,123.5	(14%)
Selling and administrative	**258.7**	244.8	6%
Franchise fees	**163.5**	175.2	(7%)
	1,465.0	1,635.5	(10%)
Depreciation and amortization	**329.7**	387.2	(15%)
Interest	**241.6**	233.5	3%
Dividends on equity preferred shares	**40.7**	32.5	25%
Income taxes	**125.4**	134.8	(7%)

Operating expenses in 2009 **decreased** by $170.5 million (10%) compared to 2008. Operation and maintenance expenses were lower primarily as a result of the impact of the ATCO Structures & Logistics Transaction, lower fuel costs in ATCO Power's Alberta and U.K. generating facilities and lower natural gas prices and volumes in NGL extraction operations in ATCO Midstream. These decreases were partially offset by higher operating costs due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). Selling and administrative expenses increased in the Utilities Segment primarily as a result of higher employment costs due to growth and higher rate hearing costs relating to regulatory applications, partially offset by lower selling and administrative costs due to the impact of the ATCO Structures & Logistics Transaction. Decreased franchise fees, recovered on a flow through basis, were paid in ATCO Gas.

In 2009, **depreciation and amortization expenses decreased** by $57.5 million (15%) compared to 2008, primarily due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by capital additions in 2008 and 2009 in the Utilities Segment.

Interest expense in 2009 **increased** by $8.1 million (3%) over 2008, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2008 and 2009 to fund capital expenditures in the Utilities Segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2008 and 2009.

Dividends on equity preferred shares in 2009 **increased** by $8.2 million (25%) over 2008 as a result of the issue by CU Inc. of $160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 on March 27, 2009.

In 2009, **income taxes decreased** by $9.4 million (7%) compared to the same period in 2008, primarily due to a $7.8 million tax adjustment as a result of the H.R. Milner Income Tax Reassessment in Alberta Power (2000) and a non-taxable gain as a result of the impact of the ATCO Structures & Logistics Transaction, partially offset by higher earnings before taxes and a $6.1 million income tax adjustment in ATCO Gas as a result of the removal of the Carbon Facility from regulation.

SEGMENTED INFORMATION

($ millions)	Utilities	Energy	For the Year Ended December 31 Corporate & Other	Intersegment Eliminations	Total
2009					
Revenues	**1,367.5**	**1,031.4**	**344.9**	**(159.8)**	**2,584.0**
Earnings attributable to Class A and Class B Shares	**195.4**	**209.5**	**60.8**	**0.9**	**466.6**
Mark-to-Market Adjustment [1]	**-**	**7.4**	**-**	**-**	**7.4**
H.R. Milner Income Tax Reassessment [2]	**-**	**(16.8)**	**-**	**-**	**(16.8)**
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management [3]	**-**	**-**	**(29.6)**	**-**	**(29.6)**
Adjusted Earnings	**195.4**	**200.1**	**31.2**	**0.9**	**427.6**
Capital expenditures	**776.1**	**151.5**	**18.5**	**-**	**946.1**
Operating expenses	**772.2**	**591.5**	**262.4**	**(161.1)**	**1,465.0**
2008					
Revenues	1,260.9	1,242.7	447.3	(172.0)	2,778.9
Earnings attributable to Class A and Class B Shares	148.6	223.0	44.0	(1.1)	414.5
Mark-to-Market Adjustment [1]	-	2.0	-	-	2.0
Other Post Employment Benefits [4]	-	(3.9)	(3.1)	-	(7.0)
Federal Court of Appeal Decision- Mining Assets [5]	(2.2)	(0.8)	-	-	(3.0)
2008 Tax Assessment [6]	(3.3)	-	-	-	(3.3)
Adjusted Earnings	143.1	220.3	40.9	(1.1)	403.2
Capital expenditures	852.6	109.7	48.6	-	1,010.9
Operating expenses	718.7	745.8	341.4	(170.4)	1,635.5

Notes:
[1] [2] [3] [4] [5] [6] *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

Utilities

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting and service area. These utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base. The determination of a fair return to the common shareholders involves an assessment by the regulator of many factors, including returns on alternative investment opportunities of comparable risk and the level of return which will enable a utility to attract the necessary capital to fund its operations and to maintain financial integrity.

Utilities **revenues** in 2009 were $1,367.5 million, an **increase** of $106.6 million (8%) over 2008, primarily attributable to the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section) and higher AUC approved customer rates resulting from ATCO Pipelines' Negotiated Settlement. Also contributing to the increase in revenues were the impact of removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders (refer to Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section) in ATCO Gas and the impact of the 2009 generic cost of capital decision in ATCO Electric and ATCO Gas (2009 Generic Cost of Capital Decision). These increases were partially offset by the impact of applying new accounting standards in ATCO Electric, ATCO Gas and ATCO Pipelines relating to the recognition of revenues for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section) and lower franchise fees collected on behalf of municipalities in ATCO Gas.

Earnings for 2009 were $195.4 million, an **increase** of $46.8 million (31%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2009, **Adjusted Earnings** were $195.4 million, an **increase** of $52.3 million (37%) over 2008. The primary reasons for higher Adjusted Earnings were the impact of the ATCO Pipelines' Negotiated Settlement, lower operating and maintenance costs as compared to amounts that were included in ATCO Electric's and ATCO Gas' customer rates primarily due to cost efficiencies, the impact of increased rate base in ATCO Electric and ATCO Gas and the impact of the removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders. These increases in Adjusted Earnings were partially offset by higher financing costs in ATCO Electric compared to amounts included in customer rates and lower sales in ATCO Gas due to lower customer growth compared to amounts included in customer rates.

Regulatory Developments

Generic Cost of Capital

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity (ROE) at 9.0% for all Alberta utilities which it regulates. This is an increase over the 8.61% ROE that the adjustment formula formerly in place would have provided for 2009. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric's transmission operations, 39% for both ATCO Electric's distribution operations and ATCO Gas' operations and 45% for ATCO Pipelines' operations. As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. The financial impact of this decision was an increase to ATCO Electric's earnings of $4.2 million and ATCO Gas' earnings of $2.5 million, of which $0.4 million relates to 2008. The changes did not apply to ATCO Pipelines for 2009 since capital structure and rate of return were included in ATCO Pipelines' Negotiated Settlement.

While ATCO Gas' ROE for 2008 was not impacted by the decision issued on November 12, 2009, a separate module within the generic proceeding addressed ATCO Gas' 2008 capital structure, as inclusion of this issue was removed from its 2008/2009 general rate application. The November 12, 2009 decision approved an equity ratio of 39% commencing in the year 2008 for ATCO Gas. The financial impact is identified in the 2008 amount noted above.

Pension Hearing

In July 2009, the ATCO Utilities submitted an application to the AUC requesting the creation of deferral accounts to record company contributions to the Canadian Utilities pension plan which are expected to be incurred in 2010. The recovery of amounts paid and recorded in the deferral accounts would be through an increase in customer rates. A hearing was held in January 2010 and with normal process a decision from the AUC is expected in the second quarter of 2010.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process.

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the Placeholder rates was filed with the AUC. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010.

All parties continue to support the calculation of fair market value provided in the benchmarking report. The issue in the regulatory proceeding is whether fair market value or some other basis should be used to finalize the Placeholders. If fair market value is used as the basis to finalize the Placeholders for the period 2003-2007 then there will not be a material impact on consolidated earnings.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008-2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010 for an interim period, the term of which will be determined in the upcoming regulatory process.

Income Tax Module

On November 12, 2009, the AUC issued its Income Tax Module decision in which it addressed the 2008-2009 income tax Placeholder amounts for ATCO Gas and 2009-2010 Placeholders for ATCO Electric. The AUC approved the Placeholder amounts as filed and established an income tax deferral account for ATCO Electric and ATCO Gas, resulting in no impact to earnings for ATCO Electric and a $2.5 million reduction in earnings for ATCO Gas.

Utility Asset Disposition Rate Review Proceeding

In March 2008, the AUC initiated a proceeding to consider the potential rate related implications for Alberta utilities of the Supreme Court of Canada's 2006 Calgary Stores Block decision (Stores Block Decision). The Calgary Stores Block matter involved the disposition by ATCO Gas of its Calgary Stores Block facility and adjacent property in downtown Calgary. The Supreme Court held that utility shareholders were entitled to receive all proceeds resulting from the sale.

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility decision discussed below). The AUC has stated that it would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow for various related matters currently before the courts to be addressed.

ATCO Electric

2009 and 2010 General Tariff Application

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. On March 11, 2009, ATCO Electric filed an application requesting an increase to its approved interim refundable rates for its distribution operations. A decision from the AUC was received on April 22, 2009, which resulted in an increase to the interim refundable rates to 67% of the requested rate increase.

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application. The effect of the decision increased ATCO Electric's 2009 annual earnings approximately $10 million compared to 2008. This increase is primarily the result of an increase in rate base of $290 million compared to 2008. In the decision, the AUC used Placeholders for 2009 and 2010 information technology and customer care and billing rates and pension costs. These Placeholders will be determined by the AUC in subsequent proceedings. The Placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The Placeholders in the decision for the income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

Transmission Infrastructure Projects

Northwest Alberta Transmission Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of four distinct transmission line projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2012.

To date, all four transmission line projects have been assigned to ATCO Electric by the AESO with final approval having been received from the AUC for three of these projects relating to the construction of 622 kilometres of transmission line with an estimated cost of $425.0 million and anticipated completion by March 31, 2011. ATCO Electric has completed construction of one 226 kilometre major transmission line and is currently constructing two other transmission lines in northwest Alberta totaling approximately 396 kilometres. In addition to the three transmission line projects, seven additional infrastructure projects in the northwest with an estimated cost of $58.0 million are anticipated to be complete by the end of 2010.

The total cost estimate and timing of the remaining transmission line project to be approved by the AUC in northwest Alberta is dependent on changing economic conditions as well as receiving all regulatory approvals on a timely basis. As a result of these variables, ATCO Electric is unable at this time to determine the completion dates or the cost of the entire project.

AESO Long-Term Transmission System Plan

In June 2009, the AESO announced its long-term transmission system plan which is in addition to the increased transmission infrastructure in northwest Alberta. This plan identifies $8.1 billion of critical transmission infrastructure projects that are needed between 2010 and 2017 to meet current and future electricity needs in Alberta and a further $6.4 billion in projects that are at a less advanced stage of planning. The Alberta government passed amendments to the Alberta Utilities Commission Act, the Electric Utilities Act, and the Hydro and Electric Energy Act to expedite the determination of these critical transmission infrastructure projects. The amendments to the Electric Utilities Act allow the government to direct assign projects, utilize service territory assignments or put major projects out for bid.

On August 25, 2009, ATCO Electric was authorized by the Alberta Minister of Energy to prepare a facilities application to build and operate a new high-voltage transmission line along a corridor on the east side of the province between Edmonton and Calgary. On December 9, 2009, the Alberta Minister of Energy amended its August 2009 authorization to ATCO Electric to allow for a staging of the requirements over a number of years. Following approval of the facilities application by the AUC, ATCO Electric will construct and operate the new line. The AESO, in its long-term transmission system plan, estimates the project will cost $1.65 billion, in 2008 dollars, and it is anticipated that the majority of these costs will be incurred after 2011.

In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that 500 - 1,000 kilometres of transmission line projects will be required in its service area over the next five years. The increase in kilometres is mainly as a result of projects identified in the AESO's long-term transmission plan.

ATCO Gas

2008 and 2009 General Rate Application

On November 13, 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009. The effect of the decision on ATCO Gas' 2009 annual earnings was an increase of approximately $3 million over 2008 resulting primarily from an increase in rate base. In the decision, the AUC used Placeholders for 2009 information and technology and customer care and billing costs. These Placeholders will be determined by the AUC in subsequent proceedings. The Placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision

discussed above. The Placeholders for income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering $9.2 million in natural gas supply costs from customers. This decision has been the subject of a number of legal appeal proceedings initiated by the City of Calgary. The City of Calgary's current appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. A decision is expected in the first half of 2010.

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta (Carbon Facility). Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon Facility to ATCO Midstream. Due to the deregulation of the natural gas market, ATCO Gas notified the AUC that the Carbon Facility was no longer required for the provision of utility service as of April 1, 2005. As a result of numerous regulatory and legal proceedings, ATCO Gas has received approval from the AUC to remove the Carbon Facility from regulation. On December 16, 2009 a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005.

On an annual basis, the amount refunded to customers through the Carbon Rate Riders was approximately $25.0 million. In addition, on an annual basis, the revenue recovered from customers as a result of costs for the Carbon Facility was approximately $13.5 million. ATCO Gas, effective July 1, 2008, received approval from the AUC to suspend on an interim basis customer rate riders (Carbon Rate Riders) that were approved in the past to distribute net revenues related to the Carbon Facility to customers. Therefore, the annual pre-tax financial impact to ATCO Gas of the suspension of Carbon Rate Riders net of the costs for the Carbon Facility is approximately $11.5 million per year. The annual increase to ATCO Gas' earnings is approximately $8.3 million. These amounts can vary on a year to year basis as a result of changes in the price of natural gas.

Removal from Regulation

In the third quarter of 2009, ATCO Gas removed the Carbon Facility from regulation for accounting purposes. This resulted in ATCO Gas derecognizing all previously recorded regulatory assets and liabilities relating to the Carbon Facility as these amounts were no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by $1.9 million in the third quarter of 2009.

Suspension of Carbon Rate Riders

Further to its decision suspending Carbon Rate Riders on an interim basis effective July 1, 2008, the AUC on July 28, 2009 issued a decision approving a refund to customers related to the costs of the Carbon facility that were included in ATCO Gas' rates from January through June 2008. In the third quarter of 2009, ATCO Gas recorded the impact of the suspension of the Carbon Rate Riders for the period January 1, 2008 to June 30, 2008 based on a decision received on July 28, 2009. ATCO Gas recognized increased revenues of $13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008

to June 30, 2008 which was previously refunded to customers and decreased revenues of $7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net impact was an increase to ATCO Gas' revenues and earnings of $6.2 million and $4.5 million, respectively, in the third quarter of 2009.

For the remaining period of April 1, 2005 to December 31, 2007, ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of $20.5 million, excluding interest. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas. The City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could affect the amount ATCO Gas is seeking to recover from customers. A hearing for the Leave to Appeal application has been tentatively scheduled for April 28, 2010.

ATCO Pipelines

2008 and 2009 General Rate Application

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements. On March 18, 2009, the AUC issued a decision approving the negotiated settlement, including, among other things, a rate of return on common equity of 8.75% and a common equity ratio of 43% for each of 2008 and 2009. As a result of the decision, ATCO Pipelines recognized additional earnings over existing interim rates of $4.5 million in the first quarter of 2009, of which $3.7 million related to 2008.

Alberta System Integration

On September 8, 2008, ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA) announced a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NOVA to utilize their physical assets under a single rates and services structure with a single commercial interface for Alberta customers. Each company would separately manage assets within distinct operating territories within Alberta. This proposal, if approved by the AUC, is expected to end duplicate tolling and operational activities and result in more efficient regulatory processes.

On June 26, 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application). The Integration Application requests the AUC to approve that (i) integration is in the public interest, (ii) ATCO Pipelines approved revenue requirements be charged to NOVA, (iii) ATCO Pipelines customers be transitioned to NOVA, with NOVA as the customer commercial point of contact, and (iv) ATCO Pipelines and NOVA swap assets in order to establish operating areas. A negotiated settlement on ATCO Pipelines' 2010, 2011 and 2012 revenue requirements is a condition precedent of the Integration Application. A settlement on ATCO Pipelines 2010, 2011 and 2012 revenue requirements was successfully negotiated with interested parties on October 28, 2009. On November 12, 2009, ATCO Pipelines filed a request with the AUC to approve its 2010, 2011 and 2012 Revenue Requirement Settlement Application as part of its Integration Application. ATCO Pipelines expects to receive an AUC decision on the Integration Application in the first half of 2010.

Other Matters

The Corporation has a number of other less significant regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

Energy

Energy **revenues** in 2009 decreased by $211.3 million (17%) to $1,031.4 million compared to 2008 primarily due to lower merchant performance in ATCO Power's Alberta generating plants due to lower prices in the Alberta electricity market, lower exchange rates on conversion of U.K. revenues into Canadian dollars and lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations. Also contributing to the decrease in revenues were lower NGL prices and volumes and lower sales of natural gas purchased for third parties in ATCO Midstream. These decreases were partially offset by increased storage revenues in ATCO Midstream due to the timing and demand for natural gas storage.

Energy **earnings** for 2009 **decreased** by $13.5 million (6%) to $209.5 million compared to 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were $200.1 million, a **decrease** of $20.2 million (9%) compared to 2008, primarily due to lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market, the 2008 recognition of insurance proceeds from the 2007/2008 Barking outage and lower exchange rates on the conversion of U.K. earnings to Canadian dollars in ATCO Power's U.K. operations. Also contributing to the decreased earnings were lower margins and volumes for NGL extraction in ATCO Midstream. These decreases in Adjusted Earnings were partially offset by the timing and demand for natural gas storage resulting in higher storage fees in ATCO Midstream.

Power Generation

Availability of the generating plants by geographic region is set forth below:

	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
ATCO Power [1]:			
Canada	**96.3%**	94.9%	1.4%
U.K. [2]	**96.3%**	87.8%	8.5%
Australia	**96.9%**	98.7%	(1.8%)
Alberta Power (2000) [1]:			
Canada	**91.9%**	91.8%	0.1%

Notes:

(1) *Generating plant availability will fluctuate due to the timing and duration of outages.*

(2) *The higher availability for the year ended December 31, 2009, reflects the unplanned outage at the Barking generating plant which commenced on October 25, 2007. The plant returned to service in the first quarter of 2008.*

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. On March 6, 2008, ATCO Power announced that the plant had returned to service. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure, prior to the recognition of insurance proceeds, was a decrease to ATCO Power's earnings of $13.4 million (2007 earnings were decreased by $8.6 million and 2008 first quarter earnings were reduced by $4.8 million). Additionally, during the first quarter of 2008, $8.1 million of business interruption and property damage insurance proceeds were recorded ($3.3 million related to 2007 and $4.8 million related to the first quarter of 2008).

The financial impact of the failure, including the recognition of the insurance proceeds, was a decrease to the Corporation's consolidated earnings of $8.6 million in 2007 and an increase to earnings of $3.3 million for the year ended December 31, 2008, which was recorded in the first quarter of 2008. The final insurance settlement will be determined once repairs associated with the outage are complete, which is expected to be in the second quarter of 2010.

TXU Europe Settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited (TXU Europe) which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 MW Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Corporation's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Corporation's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2009, earnings after income taxes of approximately $6.4 million have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

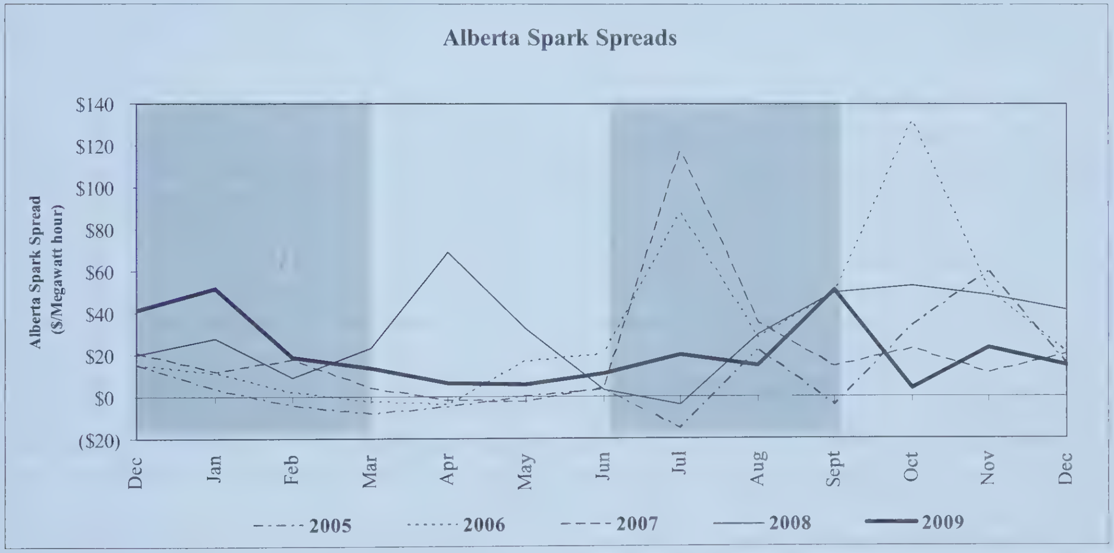
Other Power Generation Developments

On January 30, 2008, the 150 MW Unit 4 at Alberta Power (2000)'s Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. Alberta Power (2000) claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified Alberta Power (2000) that it disagreed with Alberta Power (2000)'s claim for relief under the force majeure provisions of the PPA. Unless settlement on the claim can be reached with the PPA counterparty, it is anticipated that this claim will proceed to arbitration. The cash impact resulting from this outage was approximately $11.8 million, however, due to Alberta Power (2000)'s availability incentive pool deferral account there was no material earnings impact.

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged $47.81 per MWh in 2009, compared to average prices of $89.95 per MWh in 2008. Natural gas prices averaged $3.76 per GJ, compared to average prices of $7.73 per GJ in 2008. These electricity and natural gas prices resulted in an average Spark Spread of $19.58 per MWh in 2009, compared to $32.00 per MWh in 2008.

Changes in Spark Spread currently affect the results of approximately 437 MW of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and approximately 70 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of approximately 262 MW and a worldwide owned capacity by ATCO Power and Alberta Power (2000) of approximately 2,503 MW.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta power prices and the commensurate Spark Spreads. The following chart demonstrates the volatility of Alberta Spark Spreads experienced by ATCO Power for the period of December 2004 to December 2009.



The Corporation's merchant power sales are affected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

Alberta Power (2000)

The generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to

operate the plant and be responsible for decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.64% in 2009 and 8.88% for 2008. The rate of return on common equity for 2010 is 8.44%.

Under the terms of the PPAs, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by Alberta Power (2000) when the availability targets are not achieved. These amounts are amortized based on estimates of future generating unit availability and future electricity prices over the term of the PPAs.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

During 2009, the **deferred availability incentive** account increased by \$5.9 million to \$67.1 million, mainly due to high availability offset by amortization. The amortization of deferred availability incentives, recorded in revenues, increased by \$3.7 million to \$16.3 million, primarily as a result of changes in assumptions related to the terms of the PPAs. Previous assumptions were based on a single term for the PPAs at the Battle River generating plant. These assumptions have been revised to coincide with the term of the Battle River individual unit PPAs. The change associated with the updated assumptions increased 2009 revenues by approximately \$3.8 million.

ATCO Midstream

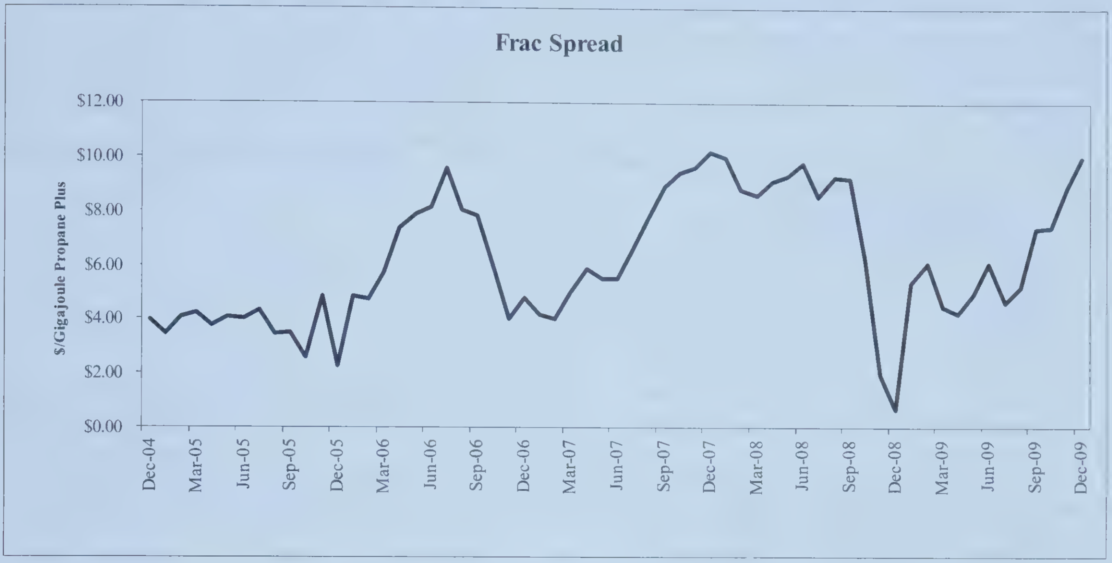
ATCO Midstream engages in non-regulated natural gas gathering, processing, storage and natural gas liquids extraction services and sales.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day of processing capacity in its NGL extraction plants.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the

prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2004 to December 2009.



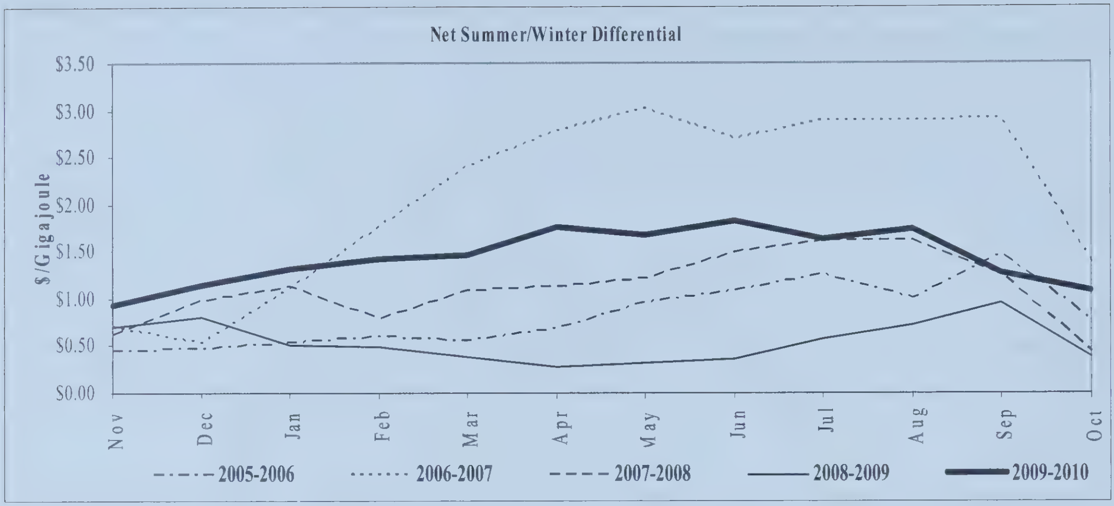
Note:
(1) *The above chart represents measurements of industry Frac Spreads in Alberta, as reported by an independent consultant.*

Fluctuations in Frac Spreads affect ATCO Midstream's earnings and cash flow from operations. At current values, a $1.00 change in the average annual Frac Spread impacts ATCO Midstream's annual earnings by approximately $6.0 million.

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (price differentials).

Summer/winter natural gas price differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal differentials experienced during the storage periods from the 2005-2006 storage year to the 2009-2010 storage year. Price differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



ATCO Midstream faces risks associated with changes to seasonal natural gas price differentials. To mitigate this risk, ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

Corporate & Other

Earnings in 2009 were $60.8 million, an **increase** of $16.8 million (38%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2009, **Adjusted Earnings** were $31.2 million, a **decrease** of $9.7 million (24%) compared to 2008. The primary reason for the decrease was lower short term interest rates on cash investments.

ATCO I-Tek

ATCO I-Tek is engaged in the development, operation and support of information systems and technologies.

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2009, ATCO I-Tek entered into a strategic relationship with Wipro, a large multinational service provider to provide joint delivery of some customer care services and to pursue new opportunities in the utility business process outsourcing market. A portion of ATCO I-Tek's call centre services is now being handled by Wipro out of the Philippines as part of this new strategic relationship.

Direct Energy entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary, which occurred on May 4, 2009, upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be approximately $500 million over the term of the contract.

Liquidity and Capital Resources

A major portion of the Corporation's operating income and funds generated by operations is generated from its utility operations. Canadian Utilities and its wholly-owned subsidiary, CU Inc., use short term bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW

	For the Year Ended December 31		
($ millions)	**2009**	2008	Change to 2009 (2009-2008)
Cash position, beginning of period	**726.6**	747.2	(3%)
Cash provided by (used in)			
Operating activities:			
Funds generated by operations	**793.4**	796.5	0%
Changes in non-cash working capital	**(55.1)**	(12.8)	(330%)
Cash flow from operations	**738.3**	783.7	(6%)
Investing activities	**(852.1)**	(806.1)	6%
Financing activities	**197.0**	13.1	1,404%
Foreign currency impact on cash balances	**(4.9)**	(11.3)	57%
Decrease in cash on ATCO Structures & Logistics transaction	**(8.9)**	-	0%
Cash position, end of period	**796.0**	726.6	10%

OPERATING ACTIVITIES

Funds generated by operations were $793.4 million in 2009, a **decrease** of $3.1 million (0%) compared to 2008. This decrease was primarily due to lower deferred availability incentives. In 2009, **cash flow from operations** was $738.3 million, a **decrease** of $45.4 million (6%) compared to 2008. This decrease was primarily due to changes in non-cash working capital.

INVESTING ACTIVITIES

In 2009, **cash used in investing activities increased** by 6% over 2008, primarily due to changes in non-cash working capital and lower contributions by utility customers for extensions to plant partially offset by lower capital expenditures. **Capital expenditures** in 2009 **decreased** by $64.8 million compared to 2008. This decrease was primarily due to decreased investment in natural gas distribution projects in ATCO Gas and the impact of the ATCO Structures & Logistics Transaction. These decreases in capital expenditures were partially offset by increased investment in non-regulated electric transmission projects by ATCO Energy Solutions and the construction of the Karratha generating plant by ATCO Power.

Capital Expenditures	**For the Year Ended December 31**		
($ millions)	**2009**	2008	Change to 2009 (2009-2008)
Utilities	**776.1**	852.6	(9%)
Energy	**151.5**	109.7	38%
Corporate & Other	**18.5**	48.6	(62%)
	946.1	1,010.9	(6%)

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.4 billion in 2010, an **increase** of $0.5 billion over 2009. The majority of these expenditures relate to the Utilities Segment. For the 2010 to 2012 period, capital expenditures in the Utilities Segment are expected to be approximately $3.5 billion to $4.5 billion (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – Transmission Infrastructure Projects section).

The planned capital expenditures for the Utilities Segment are based on the following assumptions:

- the projects identified by the AESO will proceed as currently scheduled;
- the remaining planned capital expenditures in the Utilities Segment are required to maintain capacity and meet planned growth in the Corporation's service areas. These expenditures are consistent with the anticipated growth in the Alberta economy and in the Corporation's service areas; and
- the regulatory system in Alberta will remain substantially unchanged.

In the opinion of the Corporation, these assumptions are reasonable, but no assurance can be given that these assumptions will prove to be correct.

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance of capital expenditures incurred if the AUC determines that such costs were not prudently incurred. This risk is mitigated by the inclusion of capital expenditures in general rate applications approved by the AUC. Furthermore, all major electric transmission projects assigned by the AESO to ATCO Electric are required to be approved by the AUC prior to commencing construction.

Tightness in labour and materials markets in Alberta in recent years has resulted in substantial growth in costs of many construction projects, and while the Corporation attempts to mitigate the risk of delays and cost overruns by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

FINANCING ACTIVITIES

In 2009, the Corporation had **net debt increases** of $209.8 million. **Issuance** of debt comprised of $150.0 million of 6.50% Debentures due March 7, 2039, $120.0 million of 6.215% Debentures due March 6, 2024, $89.7 million of Karratha Financing and $40.0 million of ATCO Energy Solutions Financing (refer to Business Risks - Financial Markets section). **Redemptions** were comprised of $125.0 million of 10.20% Debentures due November 30, 2009, $9.1 million of other long term debt and $55.8 million of non-recourse long term debt.

On March 27, 2009 CU Inc., a wholly-owned subsidiary of the Corporation, **issued** $160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 (for additional details on these shares, refer to Note 16 to the consolidated financial statements for the year ended December 31, 2009). The Corporation had no issues or redemptions of equity preferred shares in 2008.

In 2009 and 2008, there were **no purchases** of Class A non-voting shares under the Corporation's normal course issuer bids. In 2009, **issues** of Class A non-voting shares due to stock option exercises were $6.4 million compared to $5.0 million in 2008.

On May 23, 2008, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A Shares. The bid expired on May 22, 2009. From May 23, 2008, to May 22, 2009, no shares were purchased. The Corporation is applying to the Toronto Stock Exchange to recommence its normal course issuer bid in the first quarter of 2010.

Total **dividends increased** by 6% to $177.1 million. In 2009, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares was **increased** by $0.02 to $0.3525 per share over 2008. On January 14, 2010, the Board of Directors declared the first quarter dividend of $0.3775 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $4.9 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Corporation has a long-standing policy not to invest any of its cash balances in asset-backed securities. Cash and short term investment credit risk is reduced by investing approximately 80% in short term money market instruments of Canadian financial institutions and Government of Canada treasury bills as at December 31, 2009.

LINES OF CREDIT

At December 31, 2009, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	**Total**	**Used**	**Available**
Long term committed	326.0	48.0	278.0
Short term committed	600.0	32.0	568.0
Uncommitted	63.7	7.0	56.7
Total	989.7	87.0	902.7

The Corporation's long term committed lines of credit include:

- A $200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders; and

- A $100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. This facility will expire in August 2013, unless extended at the option of the lenders.

The Corporation's short term committed lines of credit comprise of:

- A $300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. This facility will expire in July 2010, unless extended at the option of the lenders; and
- A $300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in July 2010, unless extended at the option of the lenders.

The Corporation's uncommitted lines of credit are primarily used by its subsidiaries for liquidity purposes and for issues of letters of credit. Most of these facilities are unsecured, but some are secured by charges over assets of particular subsidiaries.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

CONTRACTUAL OBLIGATIONS

Contractual obligations for the next five years and thereafter are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
($ millions)					
Long term debt	3,120.4	127.8	246.0	189.1	2,557.5
Non-recourse long term debt	408.1	49.0	83.3	70.1	205.7
Interest expense [1]	3,059.2	225.1	404.1	373.4	2,056.6
Operating leases	108.7	18.6	29.4	22.7	38.0
Purchase obligations:					
Alberta Power (2000) coal purchase contracts [2]	512.7	51.1	106.2	112.6	242.8
Natural gas purchase contracts [3]	71.0	37.8	25.9	7.3	-
Alberta Power (2000), ATCO Power operating and maintenance agreements [4]	137.6	19.3	35.2	38.1	45.0
Capital Expenditures [5]	90.9	90.9	-	-	-
Derivatives[6]	15.5	5.6	5.4	2.4	2.1
Other	2.0	0.8	0.6	0.4	0.2
Total	7,526.1	626.0	936.1	816.1	5,147.9

Notes:

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2009. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the PPAs.*

(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating*

plant, is recovered through merchant sales in the U.K. electricity market. The ATCO Power merchant component of its generating plants in Alberta do not have any long term contracts to purchase natural gas.

(4) *Alberta Power (2000) and ATCO Power have various contracts with suppliers to provide operating and maintenance services at certain of their generating plants.*

(5) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2009.*

NET CURRENT AND LONG TERM FUTURE INCOME TAXES

Net current and long term future income taxes at December 31, 2009, were $471.5 million, an **increase** of $314.1 million (200%) over 2008. This increase was primarily due to changes in accounting policies relating to rate regulated operations (refer to Changes in Accounting Policies – Rate Regulated Operations section).

Future income taxes are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

BASE SHELF PROSPECTUS

On May 16, 2008, CU Inc. filed a **base shelf prospectus** that permits CU Inc. to issue up to an aggregate of $1,500.0 million of debentures over the twenty-five month life of the prospectus. During the year ended December 31, 2009, the following debentures were issued:

- on March 6, 2009, CU Inc. issued $150.0 million of 6.50% Debentures due March 7, 2039, and
- on March 6, 2009, CU Inc. issued $120.0 million of 6.215% Debentures due March 6, 2024.

The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines to be used to fund capital expenditures, to repay indebtedness and for other general corporate purposes.

Under its base shelf prospectus, CU Inc. has issued $0.6 billion of debentures to date, leaving $0.9 billion remaining.

Share Capital

The equity securities of the Corporation consist of Class A Shares and Class B Shares.

At February 16, 2010, the Corporation had outstanding 85,697,380 Class A Shares, 40,162,290 Class B Shares and options to purchase 871,900 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

The owners of the Class A Shares and the Class B Shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B Shares are entitled to vote and to exchange at any time each share held for one Class A Share.

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of

exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,989,500 Class A non-voting shares are available for issuance at December 31, 2009. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 16, 2010, options to purchase 871,900 Class A Shares were outstanding.

Business Risks

FINANCIAL MARKETS

Over the last year, significant challenges have been experienced in domestic and international financial markets. These challenges have had an impact on the ability of certain borrowers to finance existing operations and capital expenditure programs.

As discussed elsewhere in this MD&A, the Utilities Segment has a capital expenditure program of approximately $3.5 billion to $4.5 billion over the next three years. While the current financial situation has not directly impacted the Corporation's ability to fund this capital expenditure program and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and equity capital.

The following financings were completed during 2009:

- In March 2009, CU Inc. completed a $270 million debenture issue and a $160 million preferred share issue to fund the 2009 portion of the Utilities Segment's capital expenditure program and to fund scheduled maturities of previous debenture issues;
- On January 28, 2009, ATCO Power executed a credit facility agreement to borrow AUD$100 million to fund the construction and operations of ATCO Power's new project located in Karratha, Western Australia. The new facility has a term that covers the project's construction period plus five years of operations (Karratha Financing); and
- On June 10, 2009, the Corporation obtained an unsecured $40.0 million credit facility at an interest rate of 5.72% due June 30, 2014, to finance business activities and project expenditures for ATCO Energy Solutions (ATCO Energy Solutions Financing).

In addition, as at December 31, 2009, the Corporation has cash balances of approximately $0.8 billion and available committed and uncommitted lines of credit of approximately $0.9 billion which can be utilized for general corporate purposes.

The Corporation is unable to determine what future changes in the financial markets could occur and how these changes could affect the Corporation. Deterioration in domestic and international economic activity may impact the operations of the Corporation.

COMMODITY AND ENERGY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Corporation's operations, particularly the lower average Frac Spreads for 2009 on ATCO Midstream's NGL business.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 437 MW of merchant power capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and 70 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 262 MW. Refer to Business Risks – Non-Regulated Operations – ATCO Power section for further information.

The Corporation is unable to determine what future changes in commodity and energy markets could occur and how these changes could affect the Corporation.

PENSION PLANS

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. The Corporation has not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus positions which existed in the past and were being used to fund the employer's contributions to the defined contribution component of the pension plans.

Based on these changes, material current service and deficit funding contributions will resume in 2010. The actual funding contributions will be determined from actuarial valuations expected to be completed by May 2010. Based on the information currently available, the actual funding contributions for 2010 are expected to be in the range of $75.0 million to $90.0 million.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 75% of the costs of funding its pension plans from utility customers (refer to Segmented Information – Utilities – Regulatory Developments – Pension Hearing section). Amounts approved by the AUC may vary from the amounts requested. Based on the assumption that the full amounts requested in filed rate applications are approved by the AUC, the net funding contribution amounts (actual funding contributions less recovery from utility customers) are expected to be in the range of $15.0 million to $20.0 million. Pension funding contributions do not equate to pension expense for accounting purposes. A description of pension expense can by found in Note 23 of the Corporation's audited financial statements for the year ended December 31, 2009 which can be found on SEDAR at www.sedar.com.

ENVIRONMENTAL MATTERS

The Corporation's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products.

Greenhouse Gas Emissions

Alberta legislation requires most large emitters to reduce GHG emission intensities by up to 12% as compared to a baseline for the 2003 to 2005 period. For cogeneration and combined cycle facilities, steam production GHG emissions are also subjected to the same 12% reduction target, however these facilities are eligible for special GHG treatment and emissions credits.

Compliance reports for any GHG obligations must be submitted annually to Alberta Environment by March 31 for the previous calendar year. ATCO Power's compliance reporting obligation is expected to result in a settlement amount of 1.1 million tonnes (2008 1.3 million tonnes) including our partners share of the output of the plants emissions (approximately $16.4 million (2008 - $19.0 million) when assessed at $15/tonne). Of this total, approximately 0.8 million tonnes (2008 - 0.9 million tonnes) represented the Energy Segment's share (approximately $12.0 million (2008 - $13.6 million) when assessed at $15/tonne). This settlement amount will be achieved through a combination of approved compliance options including: improved unit performance, emission performance credits, offset credits and technology fund credits. PPA counterparties have reimbursed Alberta Power (2000) for amounts relating to their GHG obligations. Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to Alberta's GHG regulation and some of the cogeneration facilities generated emission performance credits which can be used for internal compliance as noted above.

ATCO Power participated in a working group established by Alberta Environment tasked with reviewing the method used to determine the GHG obligation for cogeneration units. A new method is expected in early 2010 that will apply to the 2010 reporting year, and could have an impact on ATCO Power's co-generation plants. Until this methodology is finalized, the impact cannot be determined.

In their most recent industry consultations in mid 2009, the federal government proposed that the regulatory framework of a new Canadian GHG Cap and Trade program would be finalized in 2010. It was expected that the program would be fully implemented by 2012. All carbon emissions would require permits. Permits would be allocated to power generation sector emitters based on historical emissions and ongoing generation. The number of permits provided to this sector would begin at 3% less than the 2006 carbon emission levels and would decrease linearly to a targeted 25% reduction in carbon emission levels by 2020. While not resolved, it was anticipated that a financial compliance mechanism would be available at the outset of the program. In addition to making physical reductions, compliance could also be accomplished by purchasing offsets or through permit trading.

Subsequent to the Copenhagen Conference of the Parties, Canada has aligned its GHG target with the United States at a 17% reduction from 2005 levels by 2020. Further, the Federal Government has stated that it intends to align its form of regulation (either traditional "command and control" or "Cap and Trade") with the approach of the United States. Accordingly, significant regulatory uncertainty and a wide range of potential outcomes remain. ATCO Power continues to monitor and actively engage the Federal Government in this area to manage the associated risks.

It is anticipated that, once the federal GHG program is finalized, the Alberta GHG program will be harmonized to the federal program.

The Barking generating plant in the U.K. complies with the European Union Emissions Trading Scheme (EU-ETS) which is currently in its second phase until the end of 2012. Under this second of three phases, Barking is allocated a free allowance of 1.4 million tonnes towards total annual emissions of 2.8 million tonnes. Barking's long term power purchasers are responsible for 72.5% of the plants emissions. For emissions relating to merchant power generation, Barking purchases allowances in the market concurrently with forward power sales which currently provide a full recovery of these compliance costs.

ATCO Power's Australian generating plants are expected to be regulated by the Australian Government's proposed carbon pollution reduction legislation. All of ATCO Power's Australian plants, both in service and under construction have long term contractual power purchase arrangements allowing full recovery of costs associated with complying with any emissions regulations.

Air Pollutants

Alberta regulation requires coal-fired generating plant operators, including Alberta Power (2000), to monitor mercury emissions and target a capture of at least 70% of the mercury in the coal commencing January 1, 2011. Alberta Environment has approved the Corporation's proposed solution and installation of mercury control equipment at the Battle River and Sheerness generating plants. Installation of this equipment began in 2009 and is expected to be operational in 2010.

The Clean Air Strategic Alliance is conducting a review of air emissions standards (sulphur dioxide, nitrogen oxides, mercury, and particulate matter) for the power generation sector in Alberta. The Energy Segment participates in this process which will develop new air emissions standards for new units and units at the end of their design life (40 years or the end of their PPA term for coal-fired units and 30 years for natural gas-fired units). The new standards are expected to be adopted by Alberta Environment by 2010, and to be effective January 1, 2011.

In May 2008, the federal government and the Canadian Council of Environment Ministers sanctioned a tripartite group (federal, provincial and territorial governments, industry and non-government organizations) to develop a new air management system for sulphur dioxide, nitrogen oxides, particulate matter, volatile organic compounds, mercury, and ground level ozone. They propose to have regulations in place by 2011 with implementation by 2015 for new and existing facilities. The three key elements of this proposal are: national ambient air quality standards set by the federal government, base level equipment performance standards and geographically based air quality management zones. The Energy Segment is represented on the Tripartite Steering Committee through the Canadian Electricity Association and is also participating in the working groups that have been set up to assist with the development of this air management system. It is uncertain how a federal system would impact the existing provincial frameworks.

Cost Recovery

It is anticipated that the PPAs will allow Alberta Power (2000) to recover all of the costs associated with complying with both the federal and Alberta regulations during the PPA terms. An exception to this recovery is for the emissions related to output in excess of the committed capacity in the PPA. The amount of emissions related to output in excess of this committed capacity is minimal. The Corporation's gas-fired fleet should be able to recover the majority of its compliance costs through the market. Market recovery will depend on the degree to which our competitors face similar or greater costs.

The Energy Segment continues to monitor these developments and the impact of complying with any resulting regulations.

Battle River Water Levels

As a result of recent drought conditions, the water levels in the cooling pond used by the Battle River generating plant in its production of electricity have fallen to levels below normal. In 2009, these changes did not result in the need to curtail production of electricity beyond normal summer derates to ensure water temperatures remain within acceptable limits. However, continued drought conditions could result in future curtailments of production. Should the plant experience significant curtailments due to this issue the Battle River PPA provides for force majeure protection and, as a result, the plant's earnings will not be materially affected.

REGULATED OPERATIONS

Regulated operations are conducted by the Corporation's wholly owned subsidiary CU Inc., which in turn has the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas and ATCO Pipelines. Alberta Power (2000)'s two largest generating plants are also considered regulated operations because they are governed by legislatively mandated PPAs, approved by the AUC.

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC, of costs incurred. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at an AUC approved Placeholder rate subject to further review. On December 16, 2009, a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005 (refer to Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section). The approval of the effective removal date of April 1, 2005 results in the finalization of the Placeholder rates for the lease of the Carbon storage facility to ATCO Midstream. However, the City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could also affect the Placeholder lease rate.

As a normal course of operation, the Carbon Facility is subject to drainage. In an effort to protect the Carbon Facility from drainage, ATCO Gas monitors operating pressures and from time to time commissions studies to help protect the integrity of the Carbon Facility. In those instances where it has been deemed necessary, ATCO Gas has undertaken an acreage protection program whereby it acquires the rights to surrounding properties to minimize and eliminate drainage.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process.

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the Placeholder rates was filed with the AUC. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010.

All parties continue to support the calculation of fair market value provided in the benchmarking report. The issue in the regulatory proceeding is whether fair market value or some other basis should be used to finalize the Placeholders. If fair market value is used as the basis to finalize the Placeholders for the period 2003-2007 then there will not be a material impact on consolidated earnings.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008-2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010 for an interim period, the term of which will be determined in the upcoming regulatory process.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively, Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to Direct Energy certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if Direct Energy fails to perform. In certain events (including where Direct Energy fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to Direct Energy by ATCO Gas and/or ATCO Electric.

Centrica plc, Direct Energy's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of Direct Energy's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to Direct Energy contemplated under the transaction agreements.

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

Alberta Power (2000)

Alberta Power (2000) has two regulated operations, the Battle River and Sheerness generating plants, which were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. For PPAs expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

NON-REGULATED OPERATIONS

ATCO Power

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and a small hydro plant. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2009, sales from approximately 69% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 31% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In the first nine months of 2010, these percentages are expected to be approximately the same. On September 30, 2010, the Barking Power

Limited revenue contracts will expire reducing the contracted capacity to approximately 58%. The U.K. and Alberta merchant sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related Spark Spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

Since October 2004, 27.5% of the power generated at ATCO Power's Barking generating plant has been sold into the U.K. power exchange market. A substantial proportion of the UK electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a fixed price gas purchase agreement which expires in September 2010 and, as a result, has been able to experience strong margins due to the high market prices for electricity that existed in the first half of 2009. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power has financed the majority of their non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in the Canadian projects subject to guarantees, excluding McMahon. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. The guarantees outstanding at December 31, 2009, are described in Note 14 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

The Corporation's generating plants are exposed to operational risks which may cause outages due to such issues as boiler, turbine, and generator failures. In order to mitigate this risk, a proactive maintenance program is carried out on a regular basis with scheduled outages for major overhauls and other maintenance issues. In addition, the Corporation carries property and business interruption insurance to protect against the risk of extended outages.

ATCO Midstream

ATCO Midstream is exposed to the difference between the selling prices of the NGL produced and the purchase price of shrinkage gas. Earnings from ATCO Midstream's NGL extraction operations will increase or decrease as the difference between the selling price of NGL and the purchase price of shrinkage gas increases or decreases.

ATCO Midstream is exposed to seasonal natural gas price differentials. The earnings and cash flow from natural gas storage operations will vary as the differences between the price of natural gas in the summer

and the following winter fluctuates. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

In June 2007, the AUC initiated an industry wide review of NGL extraction rights. On February 4, 2009, a decision was issued with respect to NOVA's natural gas transmission system that, in most cases, proposes to transfer ownership of the NGL extraction rights to the receipt point shippers (generally producers) from the border delivery shippers (generally exporters from the province who include ATCO Midstream's suppliers). The decision set out a time frame of three years for implementation and NOVA and industry stakeholders are implementing the decision and its recommendations through NOVA's Tolls, Tariff, Facilities and Procedures process. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ATCO I-Tek

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. The ATCO Utilities recently completed a review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. Remaining with ATCO I-Tek was determined to be the least expensive option and the recommendation that the ATCO Utilities submitted to the AUC. A decision from the AUC is expected in late 2010 on this recommendation.

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2009, see Note 24 to the consolidated financial statements.

The Canadian Institute of Chartered Accountants (CICA) recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003, have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
 (i) a fair value hedge of a recognized asset or liability or,
 (ii) a cash flow hedge of either:
  - a specific firm commitment or anticipated transaction or,
  - the variable future cash flows arising from a recognized asset or liability.

 At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and

measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at the time of initial recognition.

Transactions with Related Parties

On July 1, 2009 the Corporation and its parent, ATCO Ltd. finalized the ATCO Structures & Logistics Transaction. This is related party transaction. For a more detailed description refer to Company Overview – Transaction To Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section.

In other transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of \$1.5 million (2008 - \$2.6 million), provided computer operations and systems development services totaling \$3.9 million (2008 - \$14.1 million), recovered administrative expenses totaling \$7.8

million (2008 - $1.5 million) and incurred administrative expenses and corporate signature rights totaling $8.8 million (2008 - $8.9 million). The Corporation incurred no capital expenditures with related parties (2008 - $10.3 million that were recorded in property, plant and equipment).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling $1.4 million (2008 – $1.4 million).

At December 31, 2009, accounts receivable due from related parties amounted to $3.8 million (2008 - $3.3 million) and accounts payable due to related parties amounted to $3.5 million (2008 - $6.6 million).

Apart from the ATCO Structures & Logistics Transaction, these transactions are in the normal course of business and under normal commercial terms.

Off-Balance Sheet Arrangements

Other than the financial instruments discussed under the Derivative Financial Instruments section, the Corporation does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

DEFERRED AVAILABILITY INCENTIVES

Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2009, the Corporation

had recorded $67.1 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to $16.3 million in 2009.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $3.9 million, whereas the low case scenario would have resulted in lower revenues of approximately $4.1 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the high quality long bond yield rate plus an equity and management premium that reflects the plan asset mix. Recent actuarial guidance suggests that this premium is about 0.5%, which, when added to the high quality long bond yield rate of 7.0% at the beginning of 2009, resulted in an expected long term rate of return of 7.5% for 2009. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, asset diversification effect on portfolio returns and a recent change in the Corporation's portfolio asset mix policy.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over recent years to 7.5% in the year ended December 31, 2009. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. The liability discount rate has also declined to 6.4% at the end of 2009. The result is an increase in benefit obligations (i.e., an experience loss), which contributes to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization in 2009.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2009, are as follows: for drug costs, 6.5% starting in 2009 grading down over 15 years to 4.5%, and for other medical and dental costs, 4.5% and 4.0%, respectively, for 2009 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC decision to record the costs of employee future benefits when paid rather than accrued. Accordingly, the regulated operations, excluding Alberta Power (2000), recognize a regulatory asset or liability equal to the amount that would otherwise be recorded as expense or income.

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2009 are outlined in the following table. The sensitivities of each key assumption have been

calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2009 Pension Benefit Plans		2009 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
($ millions)				
Expected long term rate of return on plan assets				
1% increase [1]	-	(4.0)	-	-
1% decrease [1]	-	4.1	-	-
Liability discount rate				
1% increase [1]	(50.3)	(3.2)	(2.3)	(0.2)
1% decrease [1]	61.7	5.2	2.8	0.3
Future compensation rate				
1% increase [1]	12.0	1.9	-	-
1% decrease [1]	(11.1)	(1.7)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	48.9	5.8	2.1	0.4
1% decrease [1] [3]	(41.6)	(5.2)	(1.8)	(0.3)

Notes:

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Changes in Accounting Policies

Rate Regulated Operations

Effective January 1, 2009, the Canadian Institute of Chartered Accountants (CICA) removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. Previously, the Corporation followed Canadian GAAP recommendations, which were similar to standards issued by the Financial Accounting Standards Board (FASB) in the United States, which provide guidance on the recognition and measurement of assets and liabilities arising from rate regulation. As permitted by Canadian GAAP, the Corporation has applied standards issued by FASB as another source of Canadian GAAP. This change in accounting policy has been adopted prospectively with changes identified below. Although the standards are similar, key differences are outlined below.

The reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the Corporation's total assets and total liabilities. The Corporation reclassified $376.2 million at January 1, 2009, corresponding to these reserves.

Previously, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs for the utility operations. An amount corresponding to this provision is incorporated into rates charged to customers and was previously recognized in revenues. Under the new method of accounting, the Corporation does not recognize this amount in depreciation and amortization expense and revenues. The Corporation now recognizes operation and maintenance expense and revenues as actual removal and site restoration costs are incurred. As a result of the change in accounting, for the three months ended December 31, 2009, depreciation and amortization expense was $13.8 million lower, revenues were $5.9 million lower, and operations and maintenance expense was $7.9 million higher, resulting in no change in earnings. For the year ended December 31, 2009, depreciation and amortization expense was $54.0 million lower, revenues were $36.4 million lower, and operations and maintenance expense was $17.6 million higher, resulting in no change in earnings.

Effective January 1, 2009, the Corporation also adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of $255.6 million at January 1, 2009.

Concurrent with the changes in accounting for rate regulated operations noted above, the Corporation changed its presentation of changes in regulatory accounts within the statement of cash flows. Certain items relating to changes in rate regulated assets and liabilities that were previously included in investing and financing activities are now reported in operating activities. The inclusion of changes in the non-current regulatory assets and liabilities in operating activities provides more relevant information on the activities of the Corporation.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation adopted the CICA recommendations for goodwill and intangible assets which established standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets).

This change in accounting has been adopted retrospectively and had the following effect on the consolidated financial statements for the year ended December 31, 2009 and December 31, 2008:

(a) Restatement of opening retained earnings at January 1, 2008, to recognize the prior years' earnings effect of amounts capitalized prior to 2008 that do not meet the definition of intangible assets as now defined by GAAP (refer to Note 8 to the consolidated financial statements for the year ended December 31, 2009).

(b) Restatement of depreciation and amortization expense and future income taxes for 2008 for the effect of amounts capitalized and amortized in 2008 and prior periods that do not meet the definition of assets as now defined by GAAP. The amounts are not material.

(c) Restatement of opening accumulated other comprehensive income at January 1, 2008, for the effect of amounts capitalized prior to 2008 that do not meet the definition of assets as now defined by GAAP. The amounts are not material.

(d) Reclassification of $209.4 million included in property, plant and equipment and other assets to intangible assets on the balance sheet at December 31, 2008.

(e) Restatement of operating activities in the statement of cash flows for the impact of changes resulting from (b) above and a reclassification within investing activities of $51.7 million from purchases of property, plant and equipment to purchases of intangibles for 2008.

Financial Instruments Disclosure

The CICA has issued revisions to the disclosures for financial instruments requiring classifications of fair value measurement of financial instruments using a three level fair value hierarchy reflecting the significance of the inputs used in making the measurements. These revisions are effective for the Corporation's annual reporting for the year ended December 31, 2009. For a description of the financial instruments or the fair value hierarchy, refer to Note 1 to the consolidated financial statements for the year ended December 31, 2009.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards (IFRS) by publicly accountable enterprises will be required in 2011. The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences in recognition, measurement and disclosures that will need to be addressed.

The Corporation has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts.

The Corporation is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electricity Association. The Corporation participated in a collaborative process which culminated in the AUC issuing regulations that summarize the rate making accounting procedures and requirements to be used by utilities as a result of adopting IFRS. The direction provided in the AUC regulations will allow the Corporation to proceed with cost efficient changes to its financial reporting computer systems. The AUC announced that it will periodically review and amend the material contained in the regulations as circumstances warrant.

The Corporation's IFRS Conversion Project consists of three phases:

- Assessment and Diagnostic – This phase involves high level assessment to identify the key areas impacted by the transition to IFRS and to identify the International Financial Reporting Standards and Interpretations of those standards applicable to the Corporation. It also involves assessing each standard and interpretation to identify the changes required to existing accounting policies, information systems and business process. This phase is now complete.
- Design and Planning – This phase involves assessing alternative accounting policies and planning changes that need to be made to financial covenants and internal controls. Preliminary estimates are being prepared to show the impact of the quantitative impact of the new standards. Draft financial statements and notes are prepared (without any numbers) to identify additional disclosure requirements. This phase is substantially complete.
- Implementation and Review – This phase involves making changes in accounting policies and procedures and financial information systems and training staff on the implementation of the new standards. Financial information in accordance with IFRS will be collected in 2010 to allow for comparative reporting in 2011. This phase is in progress.

Position papers on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems are substantially complete and they have been discussed with the Corporation's external auditor. The Corporation has also made most of the necessary changes to its financial reporting computer systems and has completed its review of the impact of IFRS on financial covenants. As a number of the IFRS standards are changing, the position papers and the impact of IFRS on financial covenants will be updated to reflect any changes resulting from the final standards. The Corporation is currently evaluating the impact of IFRS on internal controls over financial reporting. An evaluation of the financial impact of the issues identified in the assessment and diagnostic phase was completed in 2009.

The Corporation reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board (IASB) and the International Financial Reporting Interpretations Committee. On July 23, 2009, the IASB issued an exposure draft on rate regulated activities (the Exposure Draft) and recently, IASB staff have issued a summary of their analysis of the responses to the Exposure Draft. The IASB staff is proposing that if the IASB decides to continue with the project that they approve further study and analysis of the issues raised and a revised timeline. The proposed timeline would result in a final standard being issued in the second half of 2011. The Corporation is currently evaluating the impact of the possible changes to the Exposure Draft and the timeline for issuing a final standard, on the Corporation's IFRS Conversion Project. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments, the Corporation has identified that the following areas have the greatest potential impact on the Corporation's accounting: joint arrangements, leases, asset impairment, employee benefits, regulatory accounting and customer contributions. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

The Corporation is party to numerous joint arrangements which currently use proportionate consolidation as the appropriate accounting treatment. Under proportionate accounting, the Corporation records its proportionate share of the assets, liabilities, revenues and expenses of the joint arrangement. Under the recent IFRS exposure draft on joint arrangements, if the joint arrangement (and not the Corporation) has indirect interests to share in the 'net' common outcome expected to be generated from a group of underlying assets and liabilities under the joint control of all of the venturers, the Corporation would account for those joint arrangements using equity accounting and report the investment in joint venture on the balance sheet and equity earnings on the statement of earnings.

Impairment under Canadian GAAP is a two step approach. First an entity determines if the recoverable amount (undiscounted cash flow) is less than the carrying value and, only if it is, then it determines if the fair value (selling price or discounted cash flow) is less than carrying amount. Impairment under IFRS is a one step approach where the entity considers whether the recoverable amount (higher of fair value less cost to sell or value in use discounted cash flow) is less than carrying amount. The amount of any impairment loss on transition to IFRS has not yet been determined.

The Corporation is currently party to a number of contracts with customers that will be deemed to be finance leases under IFRS. Under Canadian GAAP, the total revenue received from the customer is recorded on the statement of earnings and the related property, plant and equipment is depreciated evenly over the asset's useful life. Under IFRS, property, plant and equipment of a project which is deemed to be a finance lease will effectively be removed from the balance sheet and replaced with a present value finance lease receivable for the lease payments to be received over the remaining life of the arrangement. Payments received from the customer are allocated between revenue and principal payment based on a mortgage style calculation.

Employee benefits consist of pensions and other retirement benefits, including life insurance and medical care. IFRS allows an entity to recognize all experience and transitional gains and losses to retained earnings as at January 1, 2010. IFRS also allows an entity to subsequently recognize actuarial gains and losses in other comprehensive income. The amortization of the net pension gain that would be required under Canadian GAAP is not made under IFRS. The balance sheet also reflects the pension transition adjustment, which was initially recognized upon a change in Canadian GAAP in 2000, to retained earnings as at January 1, 2010.

Under the recent Exposure Draft on rate regulated activities identified above, the Corporation would have to record all regulatory assets and liabilities, including those pertaining to expected decisions on rate or tariff applications from the AUC, using a weighted average probability method. The Corporation does not record regulatory assets or liabilities for rate or tariff applications until it receives a decision from the AUC. In addition, all regulatory assets and liabilities, including the one for the future income tax liability, must be measured at their expected present value. However under IFRS, the future income tax liability is measured at cost. Under Canadian GAAP, both the future income tax liability and the related regulatory asset are measured at cost and not expected present value. Therefore under the Exposure Draft, the methodology for measuring the future income tax liability and the related regulatory asset are different. The IFRS exposure draft, as currently written, is not expected to materially change the recognition and measurement of other regulatory assets and liabilities under Canadian GAAP.

The Corporation obtains contributions from utility customers to construct assets in situations where it is not economic to provide service to the customer at the approved rate charged to other customers. Under IFRS, this contribution would be accounted for as deferred revenue on the basis that there is no stand-alone value for utility customers who provide these contributions without ongoing service by the Corporation. The deferred revenue will be amortized over the life of the related asset. Under Canadian GAAP, the contributions are deducted from property plant and equipment and amortized over the life of the related asset. This effectively reclassifies the unamortized customer contributions from an offset to property plant and equipment to a liability on the balance sheet.

Quarterly Results of Operations

SELECTED INFORMATION

($ millions except per share data)	For the Three Months Ended (1) (2) (3) Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
2009					
Revenues	768.6	602.7	537.1	675.6	2,584.0
Earnings attributable to Class A and Class B Shares	145.4	73.2	120.9	127.1	466.6
Earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Diluted earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Adjusted Earnings (4)	148.3	73.5	76.7	129.1	427.6
Adjusted Earnings per Class A and Class B Share (4)	1.18	0.59	0.61	1.02	3.40
2008 (5)					
Revenues	740.6	655.6	638.4	744.3	2,778.9
Earnings attributable to Class A and Class B Shares	150.3	82.7	67.0	114.5	414.5
Earnings per Class A and Class B Share	1.20	0.66	0.53	0.91	3.30
Diluted earnings per Class A and Class B Share	1.19	0.66	0.53	0.91	3.29
Adjusted Earnings (4)	150.0	70.8	71.6	110.8	403.2
Adjusted Earnings per Class A and Class B Share (4)	1.20	0.56	0.57	0.88	3.21

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the U.K., the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements, which have been prepared in accordance with GAAP, and the reporting currency is the Canadian dollar.*

(4) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

(5) *Certain numbers have been restated to reflect changes in accounting policies relating to goodwill and intangible assets (refer to Changes in Accounting Policies - Goodwill and Intangible Assets section).*

The principal factors that caused variations in financial condition and results of operations over the past eight quarters were:

- unplanned and planned outages affecting availability in ATCO Power's and Alberta Power (2000)'s generating plants;
- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of municipalities;
- fluctuations in temperatures, natural gas prices, electricity prices and related Spark Spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;

- the impact of the ATCO Structures & Logistics Transaction (refer to Company Overview – Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section);
- exchange rates;
- increase in rate base in the Utilities Segment;
- Carbon Facility decisions;
- the impact of adopting new accounting standards for the recognition of revenues and expenses for the regulated assets in the Utilities Segment (refer to Changes in Accounting Policies – Rate Regulated Operations section);
- mark-to-market adjustments in ATCO Power;
- H.R. Milner Income Tax Reassessment;
- Other Post Employment Benefits;
- Federal Court of Appeal Decision - Mining Assets;
- 2008 Tax Assessment; and
- changes in share appreciation rights expense due to changes in ATCO Class I non-voting share and the Corporation's Class A non-voting share prices.

Fourth Quarter 2009

All quarterly information in this document has been shaded to differentiate it from the annual information.

Segmented Revenue	For the Three Months Ended December 31		
($ millions)	**2009**	2008	Change to 2009 (2009-2008)
Utilities	**367.9**	330.4	11%
Energy	**296.1**	335.0	(12%)
Corporate & Other	**52.7**	128.8	(59%)
Intersegment eliminations	**(41.1)**	(49.9)	18%
Revenues	**675.6**	744.3	(9%)

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

Fourth quarter **revenues decreased** by $68.7 million primarily due to the impact of the ATCO Structures & Logistics Transaction, lower merchant performance in ATCO Power's Alberta generating plants due to lower pool prices in the Alberta electricity market and unfavourable merchant conditions in ATCO Power's U.K. operations. These decreases were partially offset by the timing and demand for natural gas storage resulting in higher storage fees in ATCO Midstream, the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section) and the impact on ATCO Gas and ATCO Electric of the 2009 Generic Cost of Capital Decision (refer to Segmented Information - Utilities – Regulatory Developments – Generic Cost of Capital section).

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

($ millions)	For the Three Months Ended December 31 [1] [2] [3] [4]		
	2009	2008	Change to 2009 (2009-2008)
Utilities	**52.8**	45.3	17%
Energy	**72.5**	65.9	10%
Corporate & Other	**1.7**	3.5	(51%)
Intersegment eliminations	**0.1**	(0.2)	150%
Earnings attributable to Class A and Class B Shares	**127.1**	114.5	11%
Earnings per Class A and Class B Share	**1.01**	0.91	11%
Diluted earnings per Class A and Class B Share	**1.01**	0.91	11%
Adjusted earnings per Class A and Class B Share	**1.02**	0.88	16%

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

(4) *Certain numbers have been restated to reflect changes in accounting policies relating to goodwill and intangible assets (refer to Changes in Accounting Policies - Goodwill and Intangible Assets section).*

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

($ millions)	For the Three Months Ended December 31				
	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Total
2009					
Earnings attributable to Class A and Class B Shares	**52.8**	**72.5**	**1.7**	**0.1**	**127.1**
Mark-to-Market Adjustment [1]	-	**2.0**	-	-	**2.0**
Adjusted Earnings	**52.8**	**74.5**	**1.7**	**0.1**	**129.1**
2008					
Earnings attributable to Class A and Class B Shares	45.3	65.9	3.5	(0.2)	114.5
Mark-to-Market Adjustment [1]	-	1.1	-	-	1.1
2008 Tax Assessment [1]	(3.3)	-	-	-	(3.3)
Other Post Employment Benefits [1]	-	(1.5)	-	-	(1.5)
Adjusted Earnings	42.0	65.5	3.5	(0.2)	110.8

Note:

(1) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

Fourth quarter **earnings increased** by $12.6 million (11%) over 2008, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings increased** by $18.3 million (17%) over 2008, primarily attributable to the timing and demand for natural gas storage in ATCO Midstream, the impact of the 2009 Generic Cost of Capital Decision and lower operating and maintenance costs as compared to amounts that were included in ATCO Electric's and ATCO Gas' customer rates primarily due to cost efficiencies. These increases were partially offset by lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market, unfavourable merchant performance in ATCO Power's U.K. operations, higher financing costs in ATCO Electric compared to amounts included in customer rates and the impact of the ATCO Structures & Logistics Transaction. Adjusted Earnings for the Corporation's 24.5% share of equity earnings in ASL for the three months ended December 31, 2009 was lower than the Adjusted Earnings for ATCO Frontec in the corresponding period of 2008.

Alberta Power Pool electricity prices for the three months ended December 31, 2009, averaged $46.27 per MWh, compared to average prices of $95.20 per MWh in 2008. Natural gas prices for the three months ended December 31, 2009, averaged $4.31 per GJ, compared to average prices of $6.35 per GJ in 2008. The consequence of these changes in electricity and natural gas prices was an average Spark Spread of $13.93 per MWh for the three months ended December 31, 2009, compared to $47.59 per MWh in 2008.

During the three months ended December 31, 2009, the **deferred availability incentive** account **increased** by $3.7 million to $67.1 million, mainly due to reduced outages in the quarter net of amortization. During the three months ended December 31, 2009, the amortization of deferred availability incentives, recorded in revenues, increased by $0.2 million to $3.7 million, compared to 2008.

Interest and other income for the fourth quarter **decreased** by $5.0 million to $9.6 million primarily as a result of the lower rates of interest earned on cash balances and the mark-to-market adjustment in ATCO Power.

OTHER EXPENSES

($ millions)	For the Three Months Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	**4.3**	3.6	19%
Purchased power	**14.3**	14.9	(4%)
Operation and maintenance	**233.5**	300.4	(22%)
Selling and administrative	**80.2**	87.2	(8%)
Franchise fees	**43.9**	42.5	3%
	376.2	448.6	(16%)
Depreciation and amortization expenses	**80.4**	100.1	(20%)
Interest	**60.7**	60.3	1%
Income taxes	**34.1**	27.2	25%
Dividends on equity preferred shares	**10.8**	8.2	32%

Fourth quarter **operating expenses decreased** by $72.4 million (16%) compared to 2008. Operation and maintenance expenses were lower, primarily as a result of the ATCO Structures & Logistics Transaction

and lower fuel costs in ATCO Power's Alberta and U.K. generating facilities. These decreases were partially offset by higher operating costs due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). Selling and administrative expenses were lower mainly due to the impact of the ATCO Structures & Logistics Transaction partially offset by high selling and administrative expenses in the Utilities Segment primarily as a result of higher employment costs due to growth.

Fourth quarter **depreciation and amortization expenses decreased** by $19.7 million (20%) compared to 2008, primarily due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by capital additions in 2008 and 2009 in the Utilities Segment.

Interest expense for the fourth quarter **increased** by $0.4 million (1%) over 2008, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2008 and 2009 to fund capital expenditures in the Utilities Segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2008 and 2009.

Income taxes in the fourth quarter **increased** by $6.9 million (25%) over 2008, mainly due to the impact of lower tax deductions in the Utilities Segment in 2009 due to the use of the flow-through tax methodology and higher earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

($ millions)	For the Three Months Ended December 31 **2009**	2008	Change to 2009 (2009-2008)
Cash position, beginning of period	**983.8**	946.1	4%
Cash provided by (used in):			
Operating activities:			
Funds Generated by Operations	**229.1**	249.1	(8%)
Changes in non-cash working capital	**(65.9)**	(79.2)	17%
Cash flow from operations	**163.2**	169.9	(4%)
Investing activities	**(196.2)**	(317.4)	38%
Financing activities	**(153.4)**	(68.8)	(123%)
Foreign currency impact on cash balances	**(1.4)**	(3.2)	56%
Cash position, end of period	**796.0**	726.6	10%

OPERATING ACTIVITIES

Funds Generated by Operations decreased by $20.0 million (8%) compared to 2008, primarily due to lower cash earnings and decreased deferred availability incentives in Alberta Power (2000). **Cash flow from operations** for the fourth quarter **decreased** by $6.7 million (4%) compared to 2008, primarily due to decreases in Funds Generated by Operations partially offset by changes in non-cash working capital.

INVESTING ACTIVITIES

Investing in the fourth quarter **decreased** by 38% compared to 2008, primarily as a result of lower capital expenditures and changes in non-cash working capital, partially offset by lower contributions by utility customers for extensions to plant. **Decreases** in **capital expenditures** reflect decreased investment in transmission and distribution projects in ATCO Electric, natural gas distribution projects in ATCO Gas and natural gas transmission projects in ATCO Pipelines.

FINANCING ACTIVITIES

In the fourth quarter, the Corporation had **net debt decreases** of $113.8 million. **Issuance** of debt comprised of $23.7 million of Karratha Financing. **Redemptions** included $125.0 million of 10.20% Debentures due November 30, 2009, $0.3 million of other long term debt and $12.2 million of non-recourse long term debt.

In the fourth quarter, the Corporation had **no issues or redemptions** of equity preferred shares.

In the fourth quarter of 2009 and 2008, there were **no purchases** of Class A Shares under the Corporation's normal course issuer bids. In the fourth quarter, **issues** of Class A Shares due to stock option exercises amounted to $3.7 million, compared to $0.1 million from the corresponding period in 2008.

In the fourth quarter, total **dividends paid to Class A and Class B share owners increased** by 6% to $44.3 million over the same period in 2008. In the fourth quarter, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares **increased** by $0.02 to $0.3525 per share.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $1.4 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

CANADIAN UTILITIES LIMITED

Consolidated Five-Year Financial Summary

(Millions of Canadian dollars, except as indicated)		2009	2008 [1]	2007 [1]	2006 [1]	2005 [1]
EARNINGS						
Revenues		**2,584.0**	2,778.9	2,404.9	2,430.4	2,515.8
Operating expenses		**1,465.0**	1,635.5	1,401.6	1,390.7	1,553.9
Depreciation and amortization		**329.7**	387.2	355.3	348.9	311.4
Interest		**241.6**	233.5	217.4	222.9	210.0
Gain on ATCO Structures & Logistics transaction		**(33.9)**	-	-	-	-
Earnings from investment in ATCO Structures & Logistics		**(7.8)**	-	-	-	-
Interest and other income		**(43.3)**	(59.1)	(64.3)	(58.5)	(36.6)
Income taxes		**125.4**	134.8	76.7	167.0	175.6
Dividends on equity preferred shares		**40.7**	32.5	34.3	35.8	35.8
Earnings attributable to Class A and Class B shares		**466.6**	414.5	383.9	323.6	265.7
Adjusted earnings [2]		**427.6**	403.2	341.0	320.5	-
SEGMENTED EARNINGS						
Utilities		**195.4**	148.6	138.2	120.0	105.9
Energy		**209.5**	223.0	203.0	181.6	146.4
Corporate & Other and eliminations		**61.7**	42.9	42.7	22.0	13.4
Earnings attributable to Class A and Class B shares		**466.6**	414.5	383.9	323.6	265.7
BALANCE SHEET						
Cash [3]		**796.0**	726.6	747.2	798.8	824.4
Property, plant and equipment and intangibles		**6,974.5**	6,216.9	5,684.8	5,432.0	5,216.0
Total assets		**9,083.6**	7,860.0	7,299.7	6,990.9	6,815.8
Capitalization:						
Long term debt		**3,102.3**	2,844.3	2,603.2	2,411.5	2,231.0
Non-recourse long term debt		**354.8**	412.4	478.1	626.7	673.8
Equity preferred shares		**785.0**	625.0	625.0	636.5	636.5
Share owners' equity [4]		**3,046.1**	2,748.5	2,517.1	2,322.9	2,222.0
Total capitalization		**7,288.2**	6,630.2	6,223.4	5,997.6	5,763.3
CASH FLOWS						
Funds generated by operations [5]		**793.4**	796.5	688.6	641.0	625.0
Capital expenditures [6]		**946.1**	1,010.9	700.8	567.7	526.7
Financing (excluding Class A and B dividends)		**374.1**	179.9	56.5	45.1	(1.4)
Class A and B dividends		**177.1**	166.8	156.8	176.7	139.6
CLASS A & B SHARES						
Shares outstanding at end of year [4] (thousands)		**125,860**	125,510	125,295	125,388	126,892
Return on equity [4] (%)		**16.1**	15.7	15.9	14.2	12.2
Earnings per share [4] ($)		**3.71**	3.30	3.06	2.57	2.09
Adjusted Earnings per share [2], [4] ($)		**3.40**	3.21	2.72	2.54	-
Dividends paid per share [4], [7] ($)		**1.41**	1.33	1.25	1.40	1.10
Equity per share [4] ($)		**24.20**	21.90	20.09	18.53	17.51
Stock market record - Class A non-voting shares ($)	High	**45.20**	51.80	55.00	48.94	46.20
	Low	**34.05**	33.11	41.83	35.15	29.55
	Close	**43.75**	40.50	46.40	47.73	43.98
Stock market record - Class B common shares ($)	High	**44.50**	51.75	54.00	48.85	45.82
	Low	**34.00**	33.04	42.00	35.72	29.63
	Close	**43.77**	40.00	46.00	47.66	43.85

(1) Certain numbers have been restated to reflect changes in accounting policies relating to rate regulated operations and goodwill and intangible assets.

(2) Adjusted earnings are defined as earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day to day operations. The adjustments in 2009 relate to the gain on ATCO Structures & Logistics transaction, H.R. Milner tax reassessment and mark-to-market adjustment. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies. Adjusted earnings have been calculated starting in 2006, as a result, adjusted earnings for 2005 is not included.

(3) Cash is defined as cash and short-term investments less bank indebtedness.

(4) Includes Class A non-voting shares and Class B common shares.

(5) Funds generated by operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(6) Includes purchases of property, plant and equipment and intangibles.

(7) Dividends paid per share include a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006.

CANADIAN UTILITIES LIMITED

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	**2009**	2008	2007	2006	2005
Utilities					
Natural gas distribution operations					
Capital expenditures [1]	**189.6**	249.7	191.6	167.4	174.0
Pipelines (thousands of kilometres)	**37.7**	37.2	36.5	35.9	35.4
Maximum daily demand (terajoules)	**2,184**	2,130	1,819	1,861	1,919
Natural gas distributed (petajoules)	**250**	238	233	219	216
Total system throughput (petajoules)	**250**	238	233	219	216
Average annual use per residential customer (gigajoules)	**121**	124	127	126	131
Customers at year-end (thousands)	**1,037.4**	1,022.2	1,001.8	969.9	939.6
Electric distribution and transmission operations					
Capital expenditures [1]	**497.8**	518.4	311.8	238.1	212.2
Power lines (thousands of kilometres)	**72.1**	71.5	70.9	70.1	69.2
Electricity distributed (millions of kilowatt hours)	**10,431**	10,594	10,744	10,286	9,926
Average annual use per residential customer (kWh)	**7,671**	7,666	7,690	7,495	7,214
Customers at year-end (thousands)	**233.1**	228.2	223.0	216.3	210.9
Natural gas transmission operations					
Capital expenditures [1]	**87.7**	81.7	87.1	97.7	84.3
Pipelines (thousands of kilometres)	**8.6**	8.4	8.4	8.4	8.3
Contract demand for pipelines system access (terajoules/day)	**4,877**	5,034	5,143	5,032	4,830
Energy					
Capital expenditures [1], [2]	**151.5**	109.7	56.7	54.0	43.4
Generating capacity operated (megawatts)	**4,885**	4,885	4,840	4,840	4,840
Generating capacity owned (megawatts)	**2,503**	2,503	2,467	2,474	2,474
Availability (%)	**94.9**	93.5	91.6	93.0	92.5
Natural gas processed (Mmcf/day)	**401**	435	478	480	476
Natural gas gathering lines (kilometres)	**1,000**	1,000	1,000	1,000	1,000

(1) Includes purchases of property, plant and equipment and intangibles.

(2) Prior year amounts restated to reflect the realigned segments.

GENERAL INFORMATION

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., Thursday, May 6, 2010 at The Fairmont Hotel Macdonald, 10065 – 100th Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A non-voting and
Class B common shares and
Second Preferred
(Series W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU
Class B common Symbol CU.X
Cumulative Redeemable Second
Preferred Shares
5.80% Series W Symbol CU.PR.A
6.00% Series X Symbol CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP
ANNUAL REPORTS
Annual Reports to Share Owners and Financial Information (Consolidated Financial Statements & Management's Discussion and Analysis) for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
Corporate Office
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Website: www.canadian-utilities.com
www.atco.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:

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